CS SB 130: KEY ISSUES & ASSESSMENT

Presentation to Senate Finance Committee
Juneau, Alaska › Thursday, April 14, 2016

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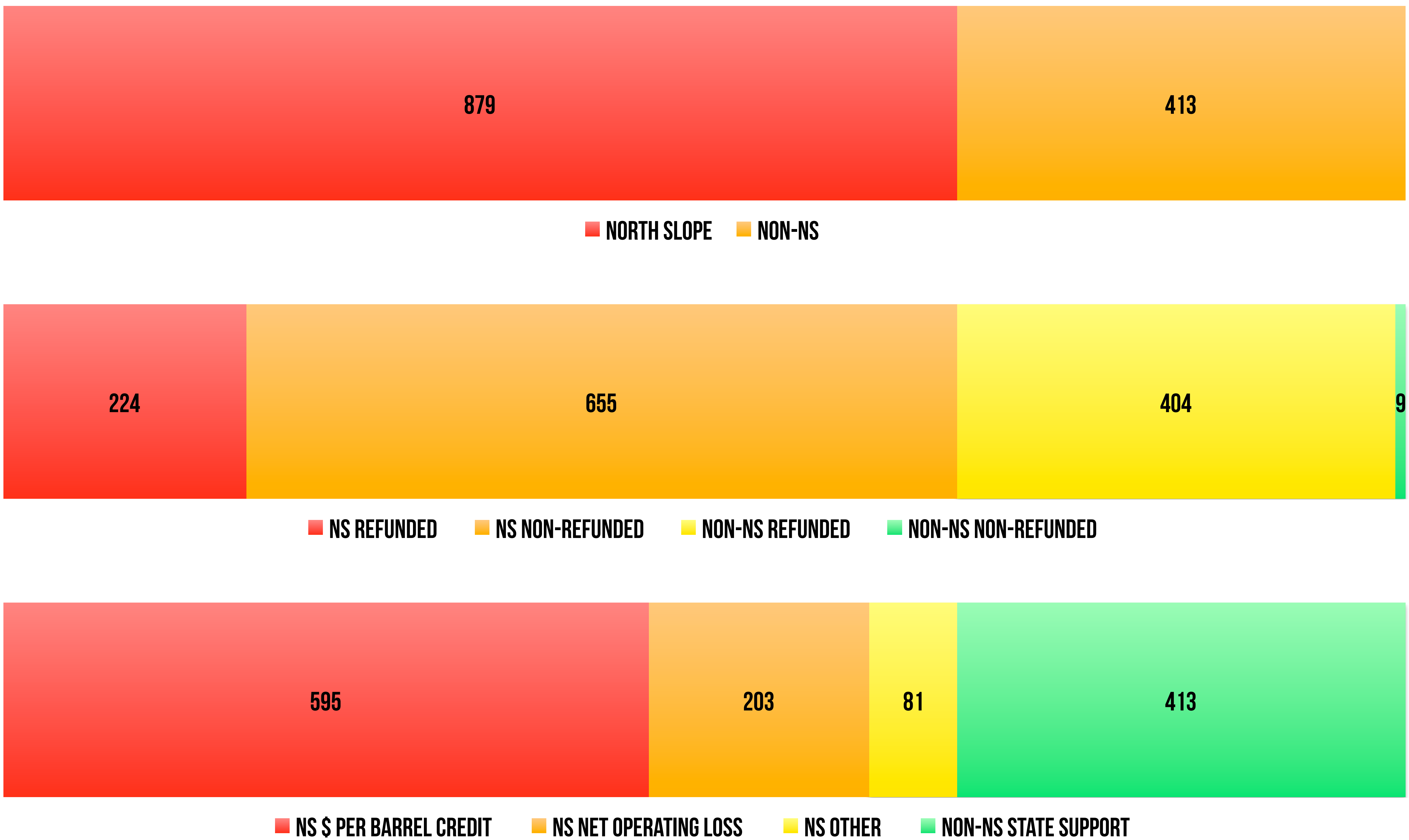
AGENDA

Issue	Status Quo	CS HB 247 (FIN) / CS SB 130 (RES)	Impact
Gross value reduction and net operating loss credit	Because GVR artificially reduces Production Tax Value, 35% NOL credit can be claimed on amount greater than actual loss - more than 35% support for spending.	Assess NOL credit on actual loss (not including GVR), so NOL is for 35% of actual loss, and all producers have 35% support for spending.	Make North Slope state support for spending uniform at 35%. Interaction is arguably an unintended consequence under SB21, though fixing has negative impact for current GVR new developments.
Time limit on gross value reduction	No current time limit on how long new developments benefit from GVR.	Allow GVR benefit only for 5 years from first production (or until 1/1/2021).	Short limit effectively eliminates much of the GVR benefit. Major negative impact on recently sanctioned eligible developments.
Refundable credit withholding	Liabilities against production tax withheld from refundable credits, but not other liabilities.	Any exploration/development/production related liabilities to the state can be withheld from refundable credit payments.	Companies in dispute over liabilities will have those amounts withheld. Companies that wish to have withholding used to settle liability may do so.
.025 'Middle Earth' exploration credit	$25 mm or 80% credit, sunsets July 1 2016.	Extend to allow for completion of wells spudded before July 1.	
Municipal production expense deduction	Munis that own production and only sell portion can deduct all expenses and claim credits.	Credits and deductions can only be claimed in proportion to taxable production.	
Surety bond	No bond requirement.	Add $250,000 bond as license requirement.	

Issue	Status Quo	CS HB 247 (FIN)	CS SB 130 (RES)	Impact
Cook Inlet Tax credits & fiscal system	25% Net Operating Loss credit, 20% Qualified Capital Expenditure credit, 40% Well Lease Expenditure credit; up to 65% gov't support for spending and minimal production tax.	Reduce NOL credit to 10%, QCE to 10%, WLE to 20% by 2018. Restrict eligibility for NOL. Working group on Cook Inlet regime.	Reduce NOL credit to 15%, QCE to 10%, WLE to 20% by 2017. No Credits and no production tax from 2018 Onward.	Cook Inlet credit regime is clearly unsustainable in current environment; degree of ramp-down / elimination has fiscal-note impact, but also potential impacts on future investment.
North Slope gross minimum tax	4% rate, binding for legacy output if net value is positive. If net value is negative, NOL can 'pierce' floor. "New," GVR-eligible production can take to zero due to $5/bbl and small producer credit.	Introduce additional, 'harder' 2% gross floor; no credits can reduce tax liability below this.	Maintain status quo - no further floor hardening.	Hardening has high fiscal-note impact, but most is revenue brought forward from future (NOL), not truly additional. Makes regressive system more so, and adds strain to cashflow-negative companies.
Refundable credit cap	Producers with >50 mb/d production must carry NOL forward, others can be reimbursed by the state. Major new NS development could place significant strain on state cashflow.	$100mm per company annual limit on reimbursement.	$85mm per company annual limit on reimbursement.	Low limit substantially increases capital needs for new developments & raises hurdle rates/break-even prices. $100mm likely not binding on companies now given current spending plans; $85mm may have negative impact on some.

Feature	Status Quo	CS HB 247 (FIN)	CS SB 130 (RES)	Impact
'Middle Earth' credits	25% Net Operating Loss credit, 20% Qualified Capital Expenditure credit, 40% Well Lease Expenditure credit.	Maintain NOL at 25%, reduce QCE to 10%, WLE to 30% by 2018. WLE may sunset in 2019?	Reduce NOL credit to 15%, QCE to 10%, WLE to 20% by 2017.	Fiscal impact of 'Middle Earth' credits currently minimal, but questions about capital credits may arise if significant development occurs.
Interest due on 'delinquent' taxes	Fed Discount Rate + 3% Simple Interest on delinquent taxes (up to 6-year audit statute of limitations).	Fed + 5% compounded quarterly for 3 yrs, then Fed + 5% simple interest (up to 6-year audit statute of limitations)	Fed + 7% compounded quarterly for 3 yrs, then no interest (up to 6-year audit statute of limitations)	Current simple interest arguably a drafting oversight from SB21 debate. Core issues here determine 'fair' rate vs companies' concerns over impact of long audit backlog on interest bills when interest rate is higher and compounded.
Alaska hire	Alaska hire not currently given preferential treatment in tax code (significant constitutional restrictions).	No change	No preferential treatment in amount of refunded credits, but companies with >75% Alaska hire placed higher in queue for refundable credit payments	

VISUALIZING ALASKA'S CREDIT SYSTEM (FY 2015)



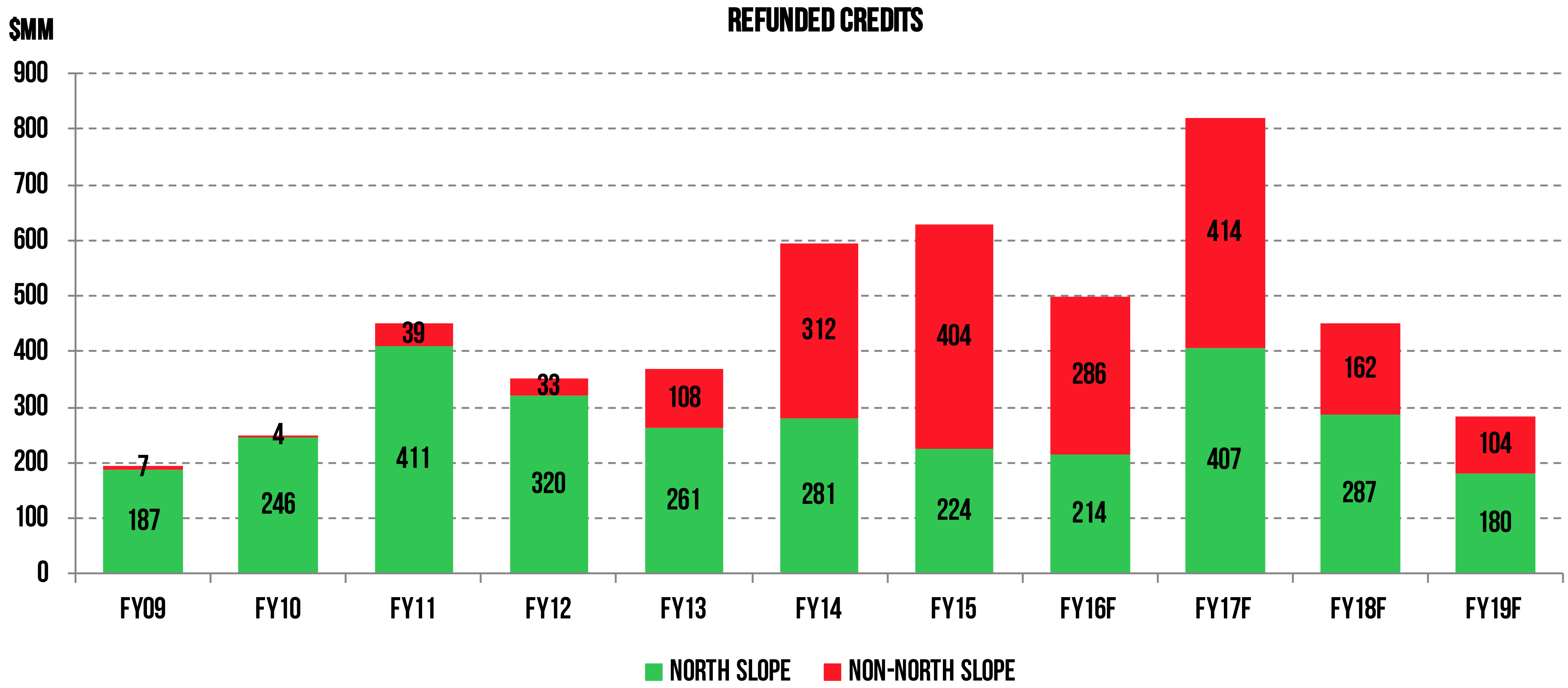
SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION

REFUNDED CREDITS REACHED NEW HIGH IN FY 2015

Refundable credits in FY 2015 reached $628 mm, the highest point ever

In both 2014 and 2015, the majority of these credits went to non-North Slope producers

Under DOR's current forecast, credits will exceed $1.3 billion across FY 2016 and FY 2017



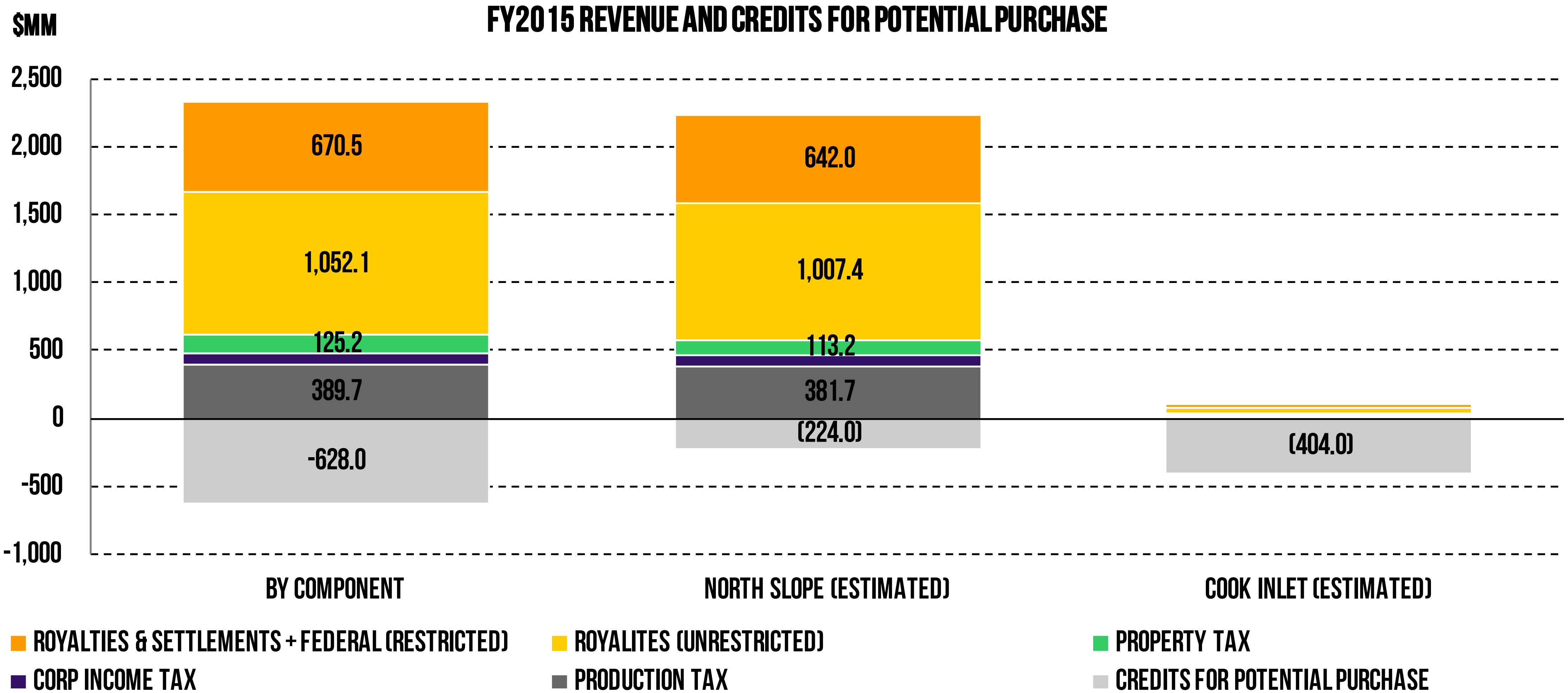
SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION

BIG DIFFERENCE BETWEEN NORTH SLOPE AND COOK INLET

The majority of refundable credits go to Cook Inlet producers

Cook Inlet production, however, generates limited direct revenue for the state

Credits on the North Slope are more limited but also a far smaller fraction of total value generated



SOURCE: ALASKA DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK; TAX DIVISION; ENALYTICA ESTIMATES

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CS SB130: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

CS SB 130: SUMMARY OF KEY ISSUES

APPENDIX

HARD TO BE BOTH NORWAY & N. DAKOTA AT SAME TIME

Gross taxes

Less volatile, shift risk to private sector

Simple and easy to administer

High/low government take at low/high prices

Disadvantages marginal investment

Net taxes

More volatile revenues for government

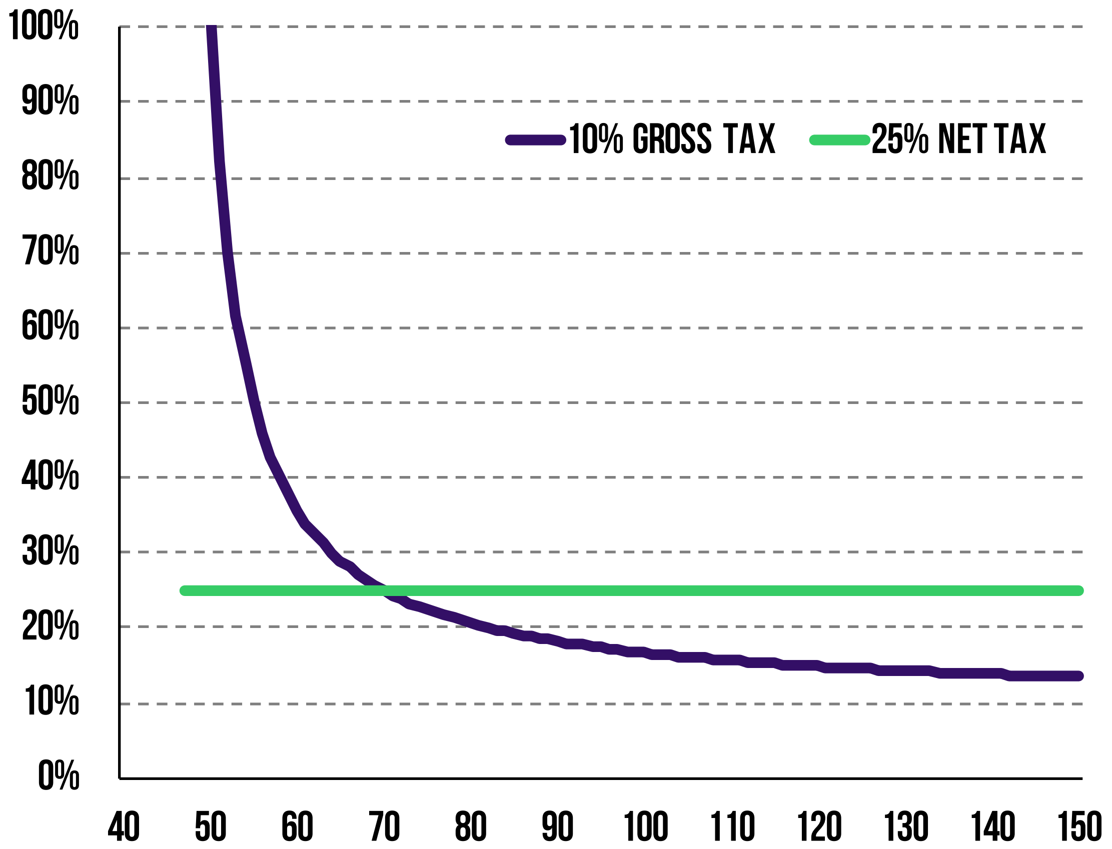
Harder to administer

Efficient—do not distort decision-making

Enable investment across commodity cycle

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	-6	14	34	54	74	94
10% GROSS TAX	3	5	7	9	11	13
% GROSS	10%	10%	10%	10%	10%	10%
% NET	#N/A	36%	21%	17%	15%	14%
25% NET TAX	-1.5	3.5	8.5	13.5	18.5	23.5
% GROSS	-5%	7%	12%	15%	17%	18%
% NET	25%	25%	25%	25%	25%	25%

EFFECTIVE TAX RATES



CASHFLOW TAXES: MORE EFFICIENT, MORE VOLATILE

Purpose of net tax is to minimize distorting impact on investment

Best achieved by making the state's fiscal cost/benefit as close as possible to equity investor

Results in outflows during development, receipts during production

HIGHLY SIMPLIFIED CASHFLOW AND INCOME EXAMPLE

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PRODUCTION (THOUSAND BBLS)	-	-	-	1,000	1,000	900	810	729	656	590
ANS WC	60	60	60	60	60	60	60	60	60	60
TRANSPORT	10	10	10	10	10	10	10	10	10	10
GVPP/BBL	50	50	50	50	50	50	50	50	50	50
GVPP ($THOUSANDS)	-	-	-	50,000	50,000	45,000	40,500	36,450	32,805	29,525
OPEX				18,000	18,000	16,200	14,580	13,122	11,810	10,629
CAPEX	20,286	60,857	33,809	20,286	-	-	-	-	-	-
PRE-TAX CASHFLOW	(20,286)	(60,857)	(33,809)	11,714	32,000	28,800	25,920	23,328	20,995	18,896
ASSET VALUE	-	-	-	135,238	108,190	86,552	69,242	55,393	44,315	35,452
DEPRECIATION	-	-	-	27,048	21,638	17,310	13,848	11,079	8,863	7,090
NET INCOME	-	-	-	4,952	10,362	11,490	12,072	12,249	12,132	11,805
25% CASHFLOW TAX	(5,071)	(15,214)	(8,452)	2,929	8,000	7,200	6,480	5,832	5,249	4,724
25% INCOME TAX	-	-	-	1,238	2,590	2,872	3,018	3,062	3,033	2,951

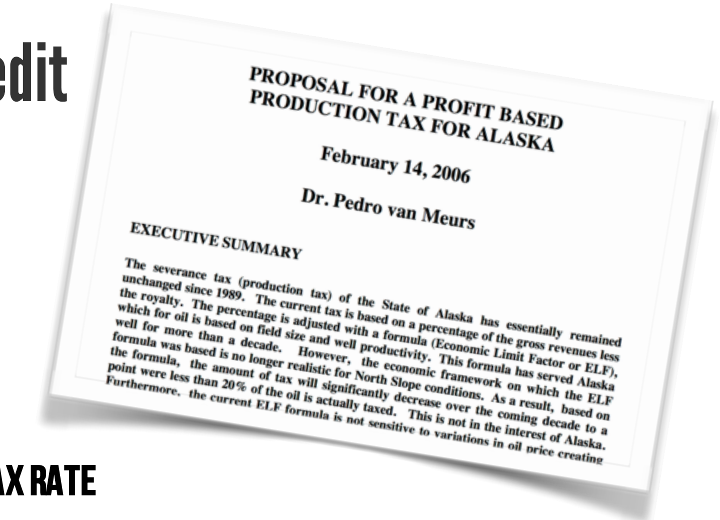
ALASKA'S PRODUCTION TAX: ORIGINS IN 2006 PROPOSAL

PPT as proposed by Dr Pedro van Meurs useful to understand core of system and evolution to date

25% flat cashflow tax, 25% credit for net operating losses (NOLs), 20% capital credit

45% government support for spending for new and incumbent players alike

Statewide floor of zero (credits tradable rather than reimbursable)



PROPOSAL FOR A PROFIT BASED PRODUCTION TAX FOR ALASKA

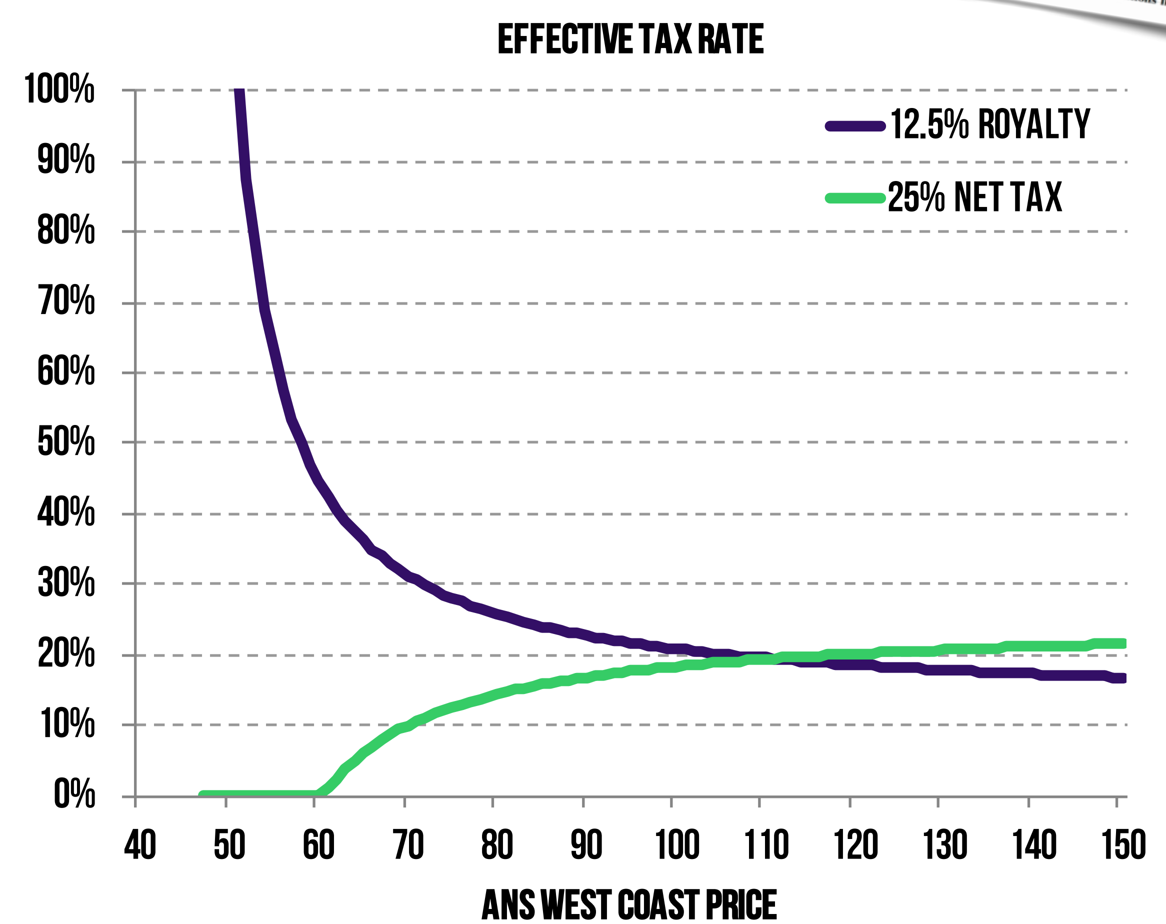
February 14, 2006

Dr. Pedro van Meurs

EXECUTIVE SUMMARY

The severance tax (production tax) of the State of Alaska has essentially remained unchanged since 1989. The current tax is based on a percentage of the gross revenues less the royalty. The percentage is adjusted with a formula (Economic Limit Factor or ELF), which for oil is based on field size and well productivity. This formula has served Alaska well for more than a decade. However, the economic framework on which the ELF formula was based is no longer realistic for North Slope conditions. As a result, based on the formula, the amount of tax will significantly decrease over the coming decade to a point were less than 20% of the oil is actually taxed. This is not in the interest of Alaska. Furthermore, the current ELF formula is not sensitive to variations in oil price creating

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
25% NET TAX	(1.5)	3.5	8.5	13.5	18.5	23.5
CAPITAL CREDIT	3.6	3.6	3.6	3.6	3.6	3.6
TAX AFTER CREDITS	(5.1)	(0.1)	4.9	9.9	14.9	19.9
% GROSS	-17%	0%	7%	11%	14%	15%
% NET	#N/	-1%	14%	18%	20%	21%



NOL CREDIT AIMS TO EQUALIZE TAX SYSTEM IMPACT

Incumbent can deduct spending against liability at marginal tax rate: 25% gov't spending support

Aim for NOL credit to ensure same impact for new developer with no liability

Alternative is to carry forward: same cash impact over time, but disadvantages new developer economics

In original proposal, credits not refundable but tradable

Aim was for new developers to sell to incumbent producers at close to face value

In reality credits sold for much less than face value - much value captured by incumbents

As a result, credits made refundable by the treasury, to direct full value to new developers

HIGHLY SIMPLIFIED CASHFLOW AND INCOME EXAMPLE

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PRODUCTION (THOUSAND BBLS)	-	-	-	1,000	1,000	900	810	729	656	590
ANS WC	60	60	60	60	60	60	60	60	60	60
TRANSPORT	10	10	10	10	10	10	10	10	10	10
GVPP/BBL	50	50	50	50	50	50	50	50	50	50
GVPP ($THOUSANDS)	-	-	-	50,000	50,000	45,000	40,500	36,450	32,805	29,525
OPEX				18,000	18,000	16,200	14,580	13,122	11,810	10,629
CAPEX	20,286	60,857	33,809	20,286	-	-	-	-	-	-
PRE-TAX CASHFLOW	(20,286)	(60,857)	(33,809)	11,714	32,000	28,800	25,920	23,328	20,995	18,896
25% CASHFLOW TAX	(5,071)	(15,214)	(8,452)	2,929	8,000	7,200	6,480	5,832	5,249	4,724

ACES: STEEP PROGRESSIVITY, HIGH SPENDING SUPPORT

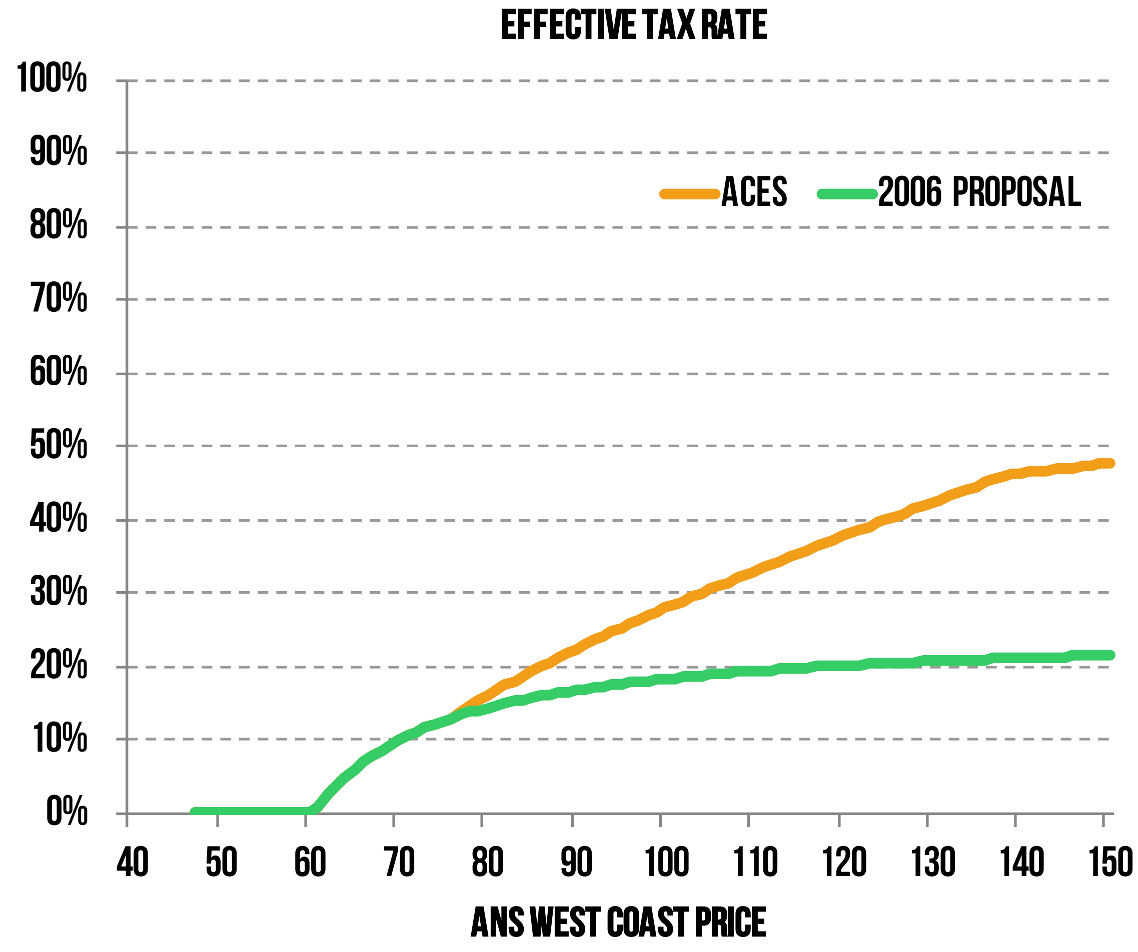
Tax rate 25% to 75% (variable with PTV/bbl), 20% capital credit, 40% exploration credit, 25% NOL credit

High progressivity: high marginal tax rates (up to 86%, higher at yet-unseen prices)

High marginal rates + credits = very high state support for spending (from 45% to over 100%)

With high prices and low spending, brought huge revenue; low prices and high spending major risks

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
NET TAX RATE	25%	25%	27%	35%	43%	50%
NET TAX CALC	-	3.5	9.0	18.7	31.5	47.1
4% GROSS FLOOR	1.2	2.0	2.8	3.6	4.4	5.2
TAX BEFORE CREDITS	1.2	3.5	9.0	18.7	31.5	47.1
NOL CREDIT	1.5	-	-	-	-	-
CAPITAL CREDIT	3.6	3.6	3.6	3.6	3.6	3.6
TAX AFTER CREDITS	(3.9)	(0.1)	5.4	15.1	27.9	43.5
% GROSS	-13%	0%	8%	17%	25%	33%
% NET	#N/A	-1%	16%	28%	38%	46%



SB21: PROTECT ON THE LOW END, GIVE BACK AT THE HIGH

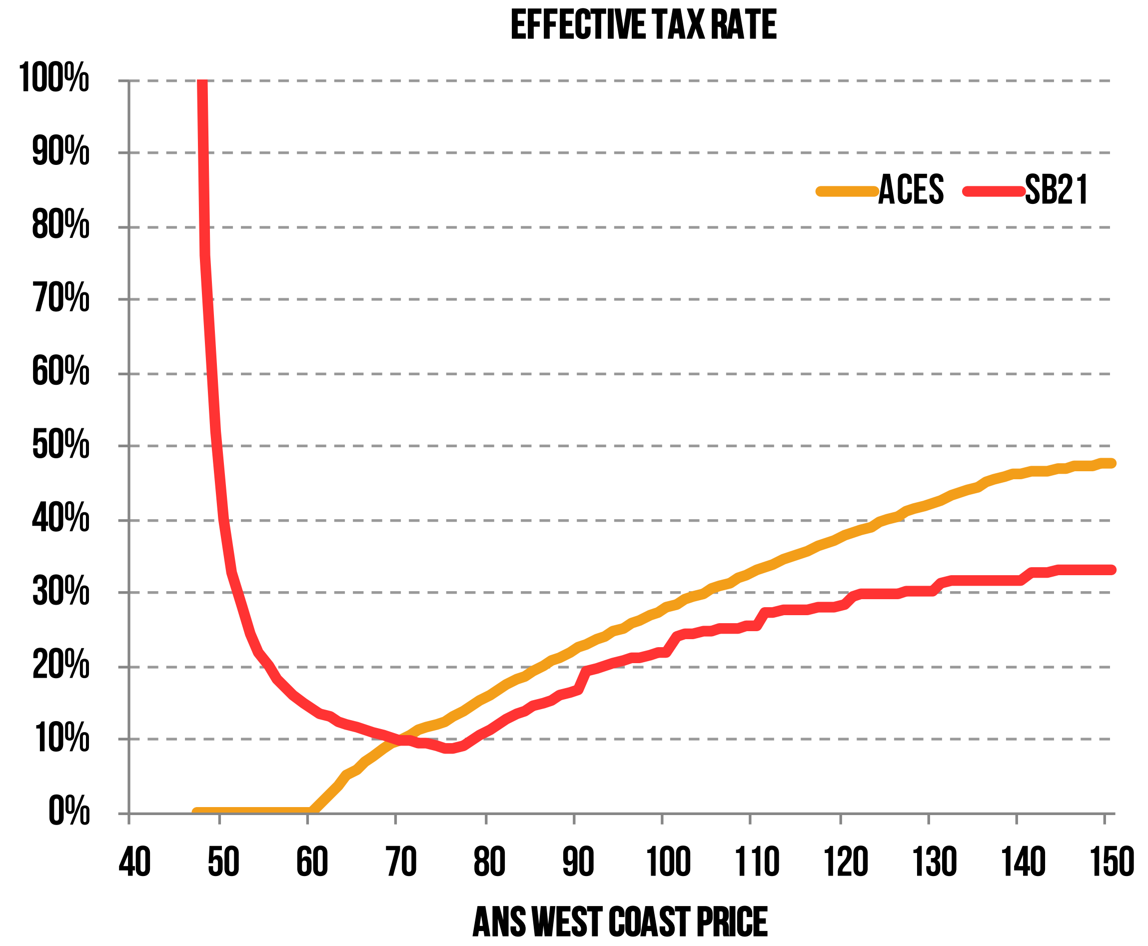
Tax rate 35%, $0 to $8 per-bbl credit, hardened gross floor, 35% NOL credit

Key aim was to reduce state support for spending and make predictable: 35% for everyone

Reduced rates at high prices for competitiveness, but 4% gross floor binding to protect at low end

Significantly reduced the risks brought by low prices and high spending

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
NET TAX RATE	35%	35%	35%	35%	35%	35%
NET TAX PRE $/BBL	-	4.9	11.9	18.9	25.9	32.9
$/BBL CREDIT	8.0	8.0	8.0	7.0	5.0	3.0
NET TAX CALC	(8.0)	(3.1)	3.9	11.9	20.9	29.9
4% GROSS FLOOR	1.2	2.0	2.8	3.6	4.4	5.2
TAX BEFORE NOL	1.2	2.0	3.9	11.9	20.9	29.9
NOL CREDIT	2.1	-	-	-	-	-
TAX AFTER CREDITS	(0.9)	2.0	3.9	11.9	20.9	29.9
% GROSS	-3%	4%	6%	13%	19%	23%
% NET	#N/A	14%	11%	22%	28%	32%



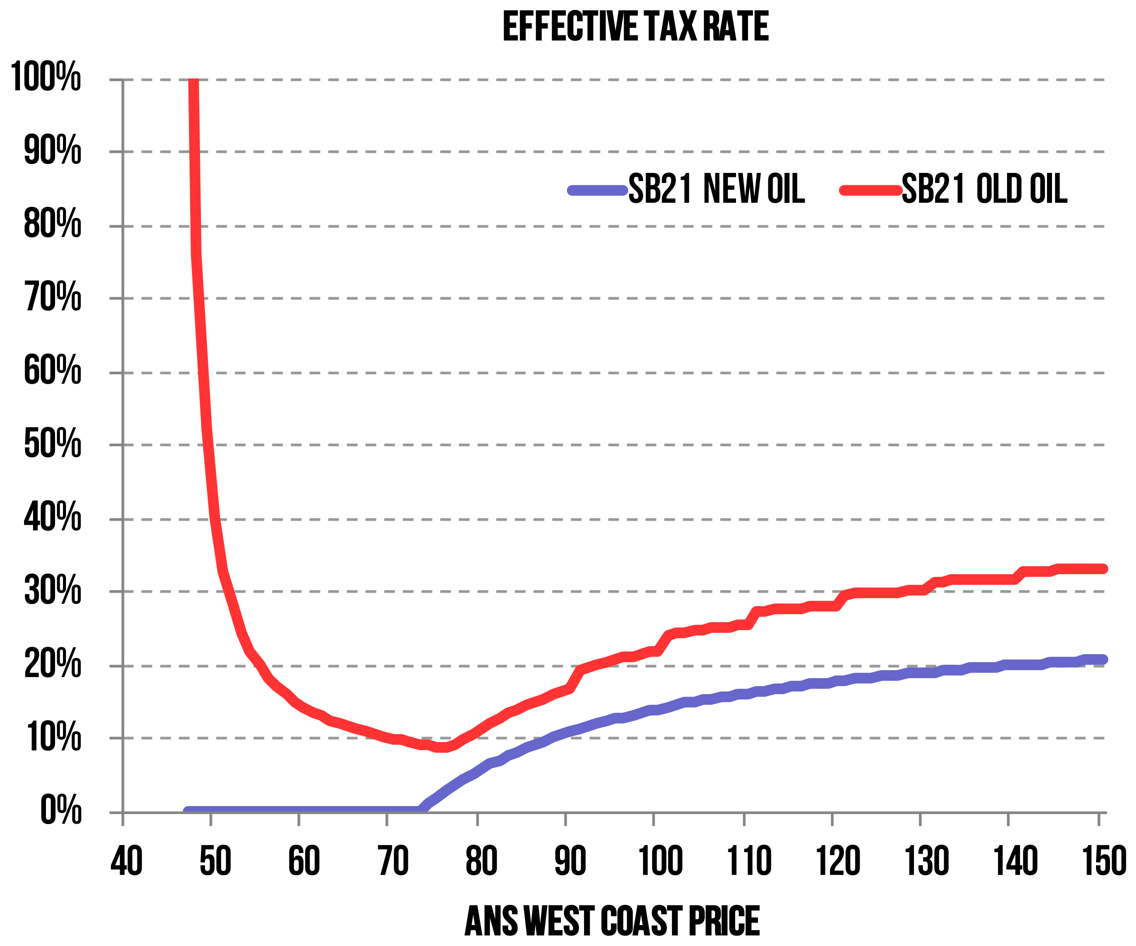
SB21: SPECIAL INCENTIVES FOR "NEW OIL"

Gross Value Reduction (GVR) - reduce GVPP by 20% or 10% for certain units / participating areas

Purpose of GVR - reduce effective tax rates for particular fields without ring-fencing costs

GVR-eligible production receives fixed $5/bbl credit, not variable $0-$8/bbl, no hard floor

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP BEFORE GVR	30	50	70	90	110	130
GVPP AFTER GVR	24	40	56	72	88	104
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL BEFORE GVR	(6.0)	14.0	34.0	54.0	74.0	94.0
PTV/BBL	(12.0)	4.0	20.0	36.0	52.0	68.0
NET TAX RATE	35%	35%	35%	35%	35%	35%
NET TAX	-	1.4	7.0	12.6	18.2	23.8
4% GROSS FLOOR	1.0	1.6	2.2	2.9	3.5	4.2
$/BBL CREDIT	5.0	5.0	5.0	5.0	5.0	5.0
TAX BEFORE NOL	(4.0)	(3.4)	2.0	7.6	13.2	18.8
NOL CREDIT	4.2	-	-	-	-	-
TAX AFTER CREDITS	(8.2)	(3.4)	2.0	7.6	13.2	18.8
% GROSS	-27%	-7%	3%	8%	12%	14%
% NET	#N/A	-24%	6%	14%	18%	20%



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NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

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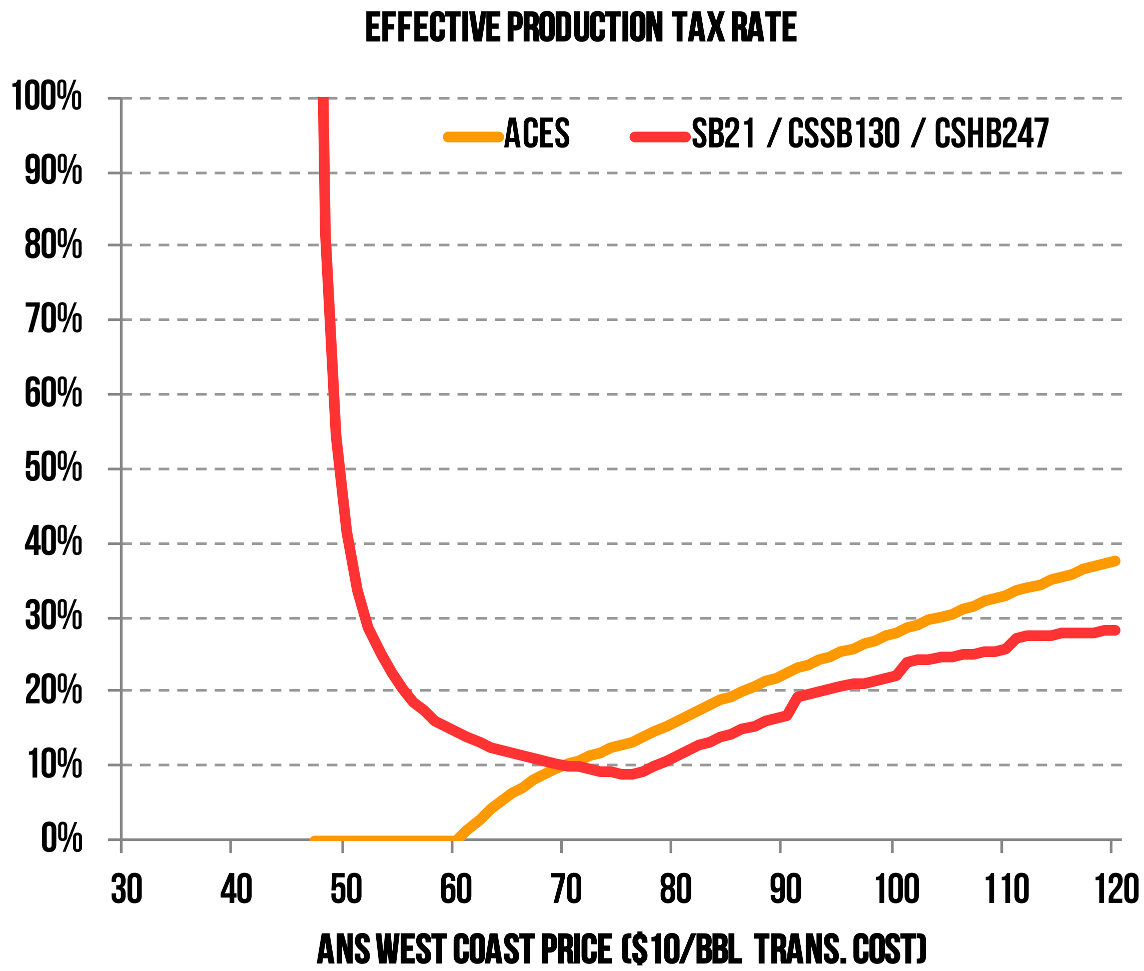
NOL-HARDENING SHIFTS REVENUE, TAXES LOSSES

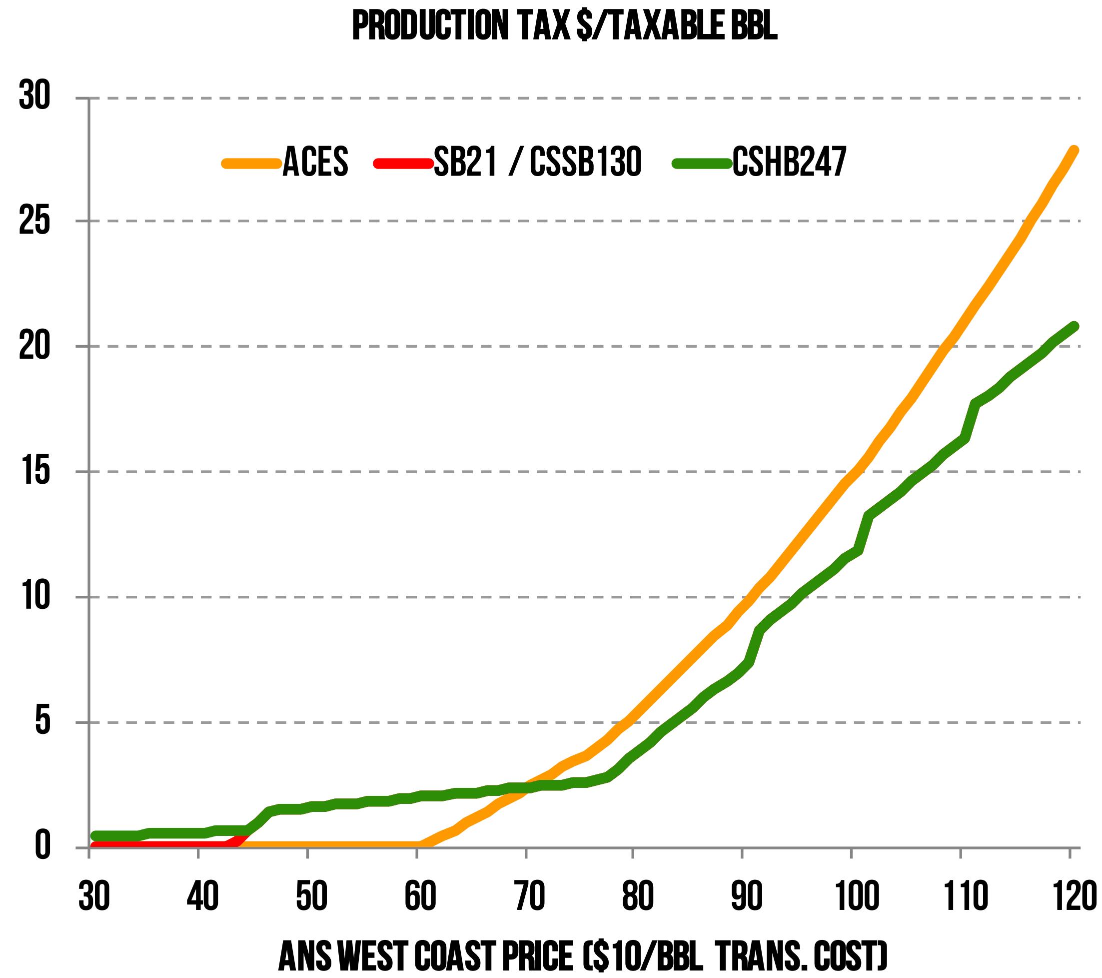
Effective tax rate under ACES could fall to zero because capital credits were applied after gross floor

SB21 applied a hard gross floor under $/bbl credits - meaning skyrocketing net tax rate at low prices

Concern to protect state at low prices always valid, but must balance risk and reward at low and high end

Preventing NOL credit from 'piercing' floor moves state revenue from future to present; total is the same



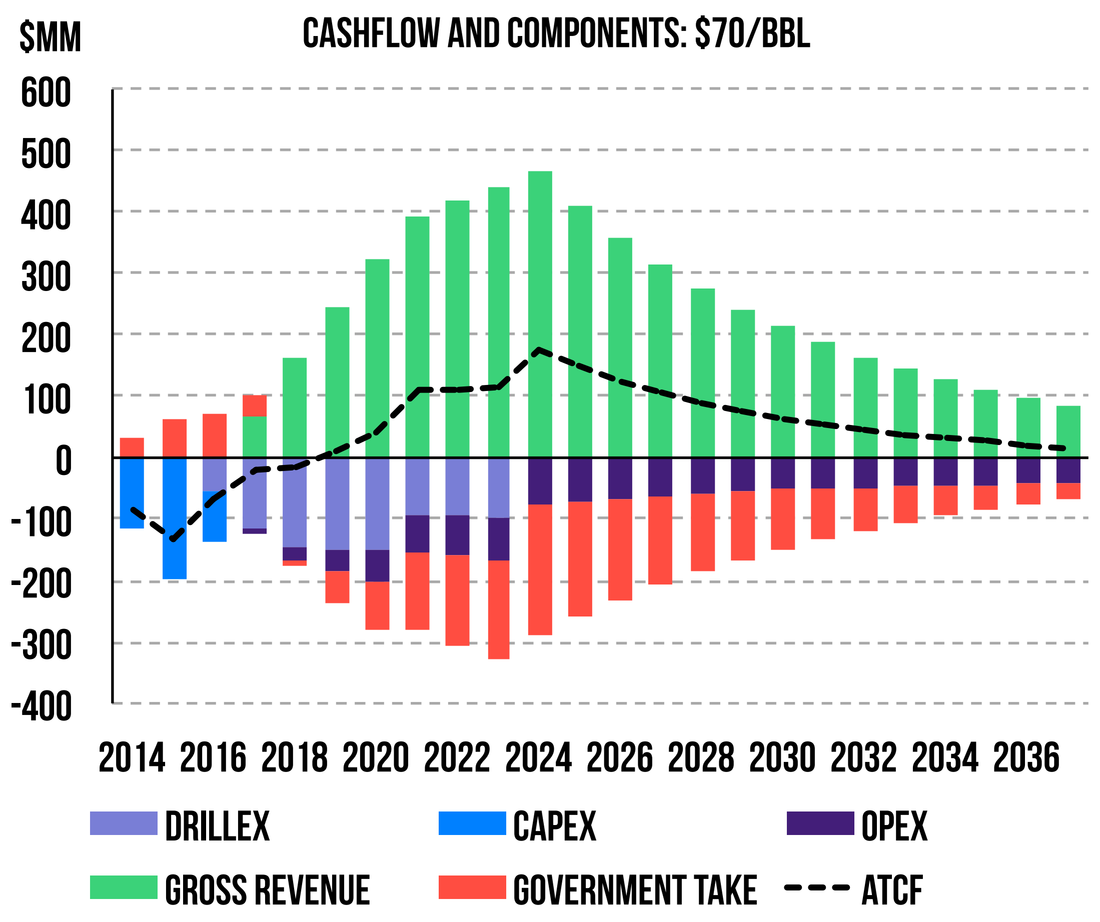


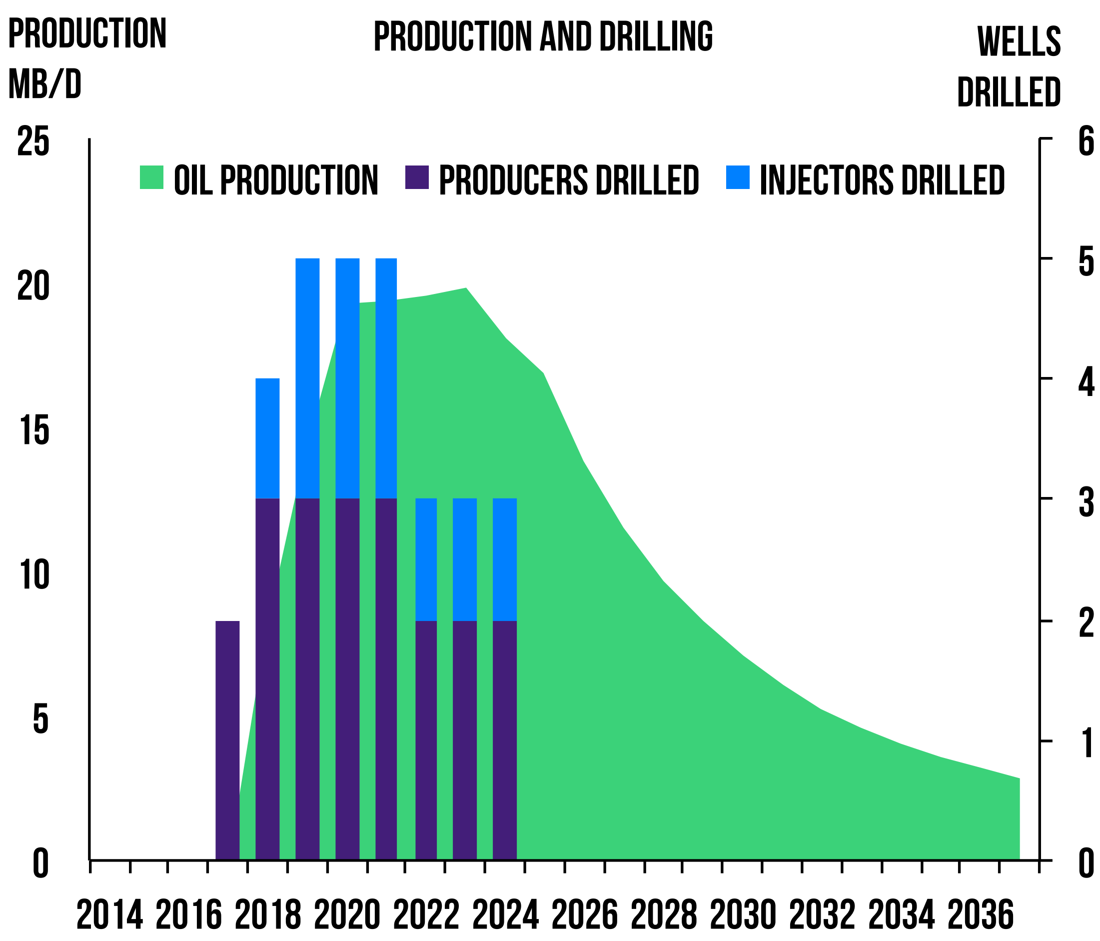
HOW DO CHANGES IMPACT NEW FIELD DEVELOPMENT?

Sample NS investment: Cumulative CAPEX and DRILLEX of $1.3 bn; average annual OPEX of about $15/bbl

Peak production of 20 mb/d; 30 wells (production and injection) drilled over 8 years

Ongoing DRILLEX in early years means bulk of tax liability occurs only after several years of production





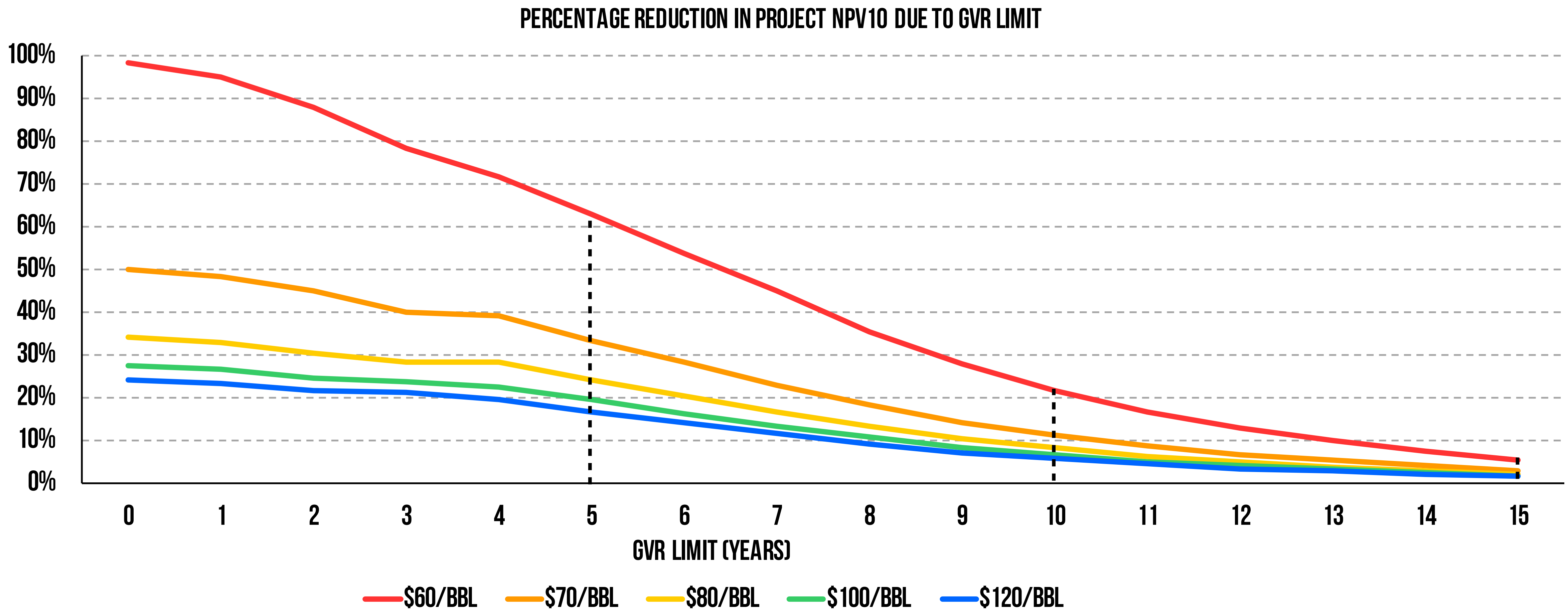
5-YEAR GVR LIMIT HAS MAJOR IMPACT ON PROJECT VALUE

Project is marginal at $60/bbl; elimination of GVR can wipe out all value at that price

Because most tax liability occurs after end of major spending, short GVR limit provides little benefit

5-year GVR limit destroys over 60% of project value at $60/bbl, relative to status quo

Impact of 10 year limit much lower; 15 year limit preserves almost all of status quo value



PREVENT GVR RAISING NOL ABOVE 35% OF ACTUAL LOSS

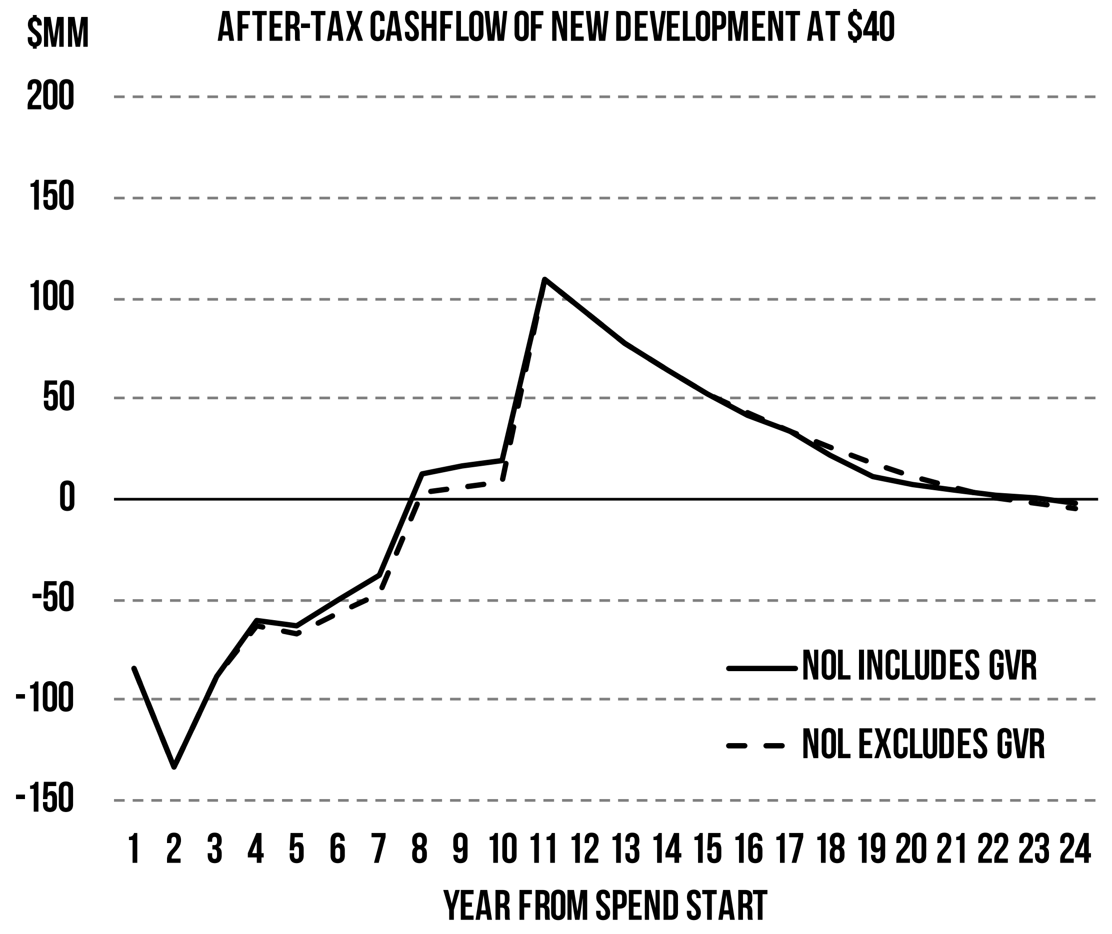
The purpose of the Gross Value Reduction (GVR) is to lower the effective tax rate on new production

One surprising and counter-intuitive effect is to raise the effective rate of the NOL credit

Issue after production from new development starts, but ongoing drilling costs mean NOL eligible

Exacerbated at low prices, but impact <$10mm yr for 20mb/d new development

	SB 21 GVR	CS SB130
ANS WC	40	40
TRANSPORT	10	10
GVPP BEFORE GVR	30	30
GVPP AFTER GVR	24	24
OPEX	18	18
CAPEX	18	18
PTV/BBL BEFORE GVR	(6.0)	(6.0)
PTV/BBL	(12.0)	(12.0)
NET TAX RATE	35%	35%
NET TAX	-	-
4% GROSS FLOOR	1.0	1.0
$/BBL CREDIT	5.0	5.0
TAX BEFORE NOL	(4.0)	(4.0)
NOL CREDIT	4.2	2.1
TAX AFTER CREDITS	(8.2)	(6.1)
CREDIT % PTV (BEFORE	-70%	-35%

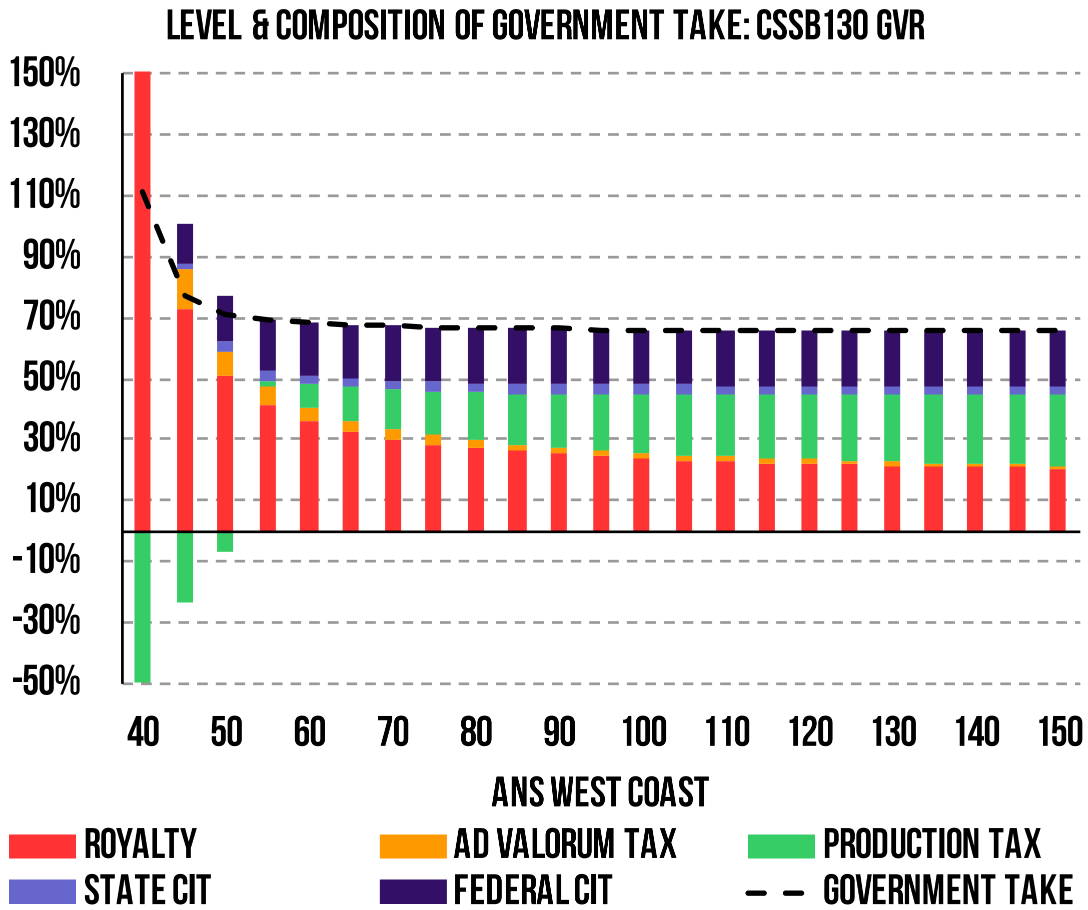


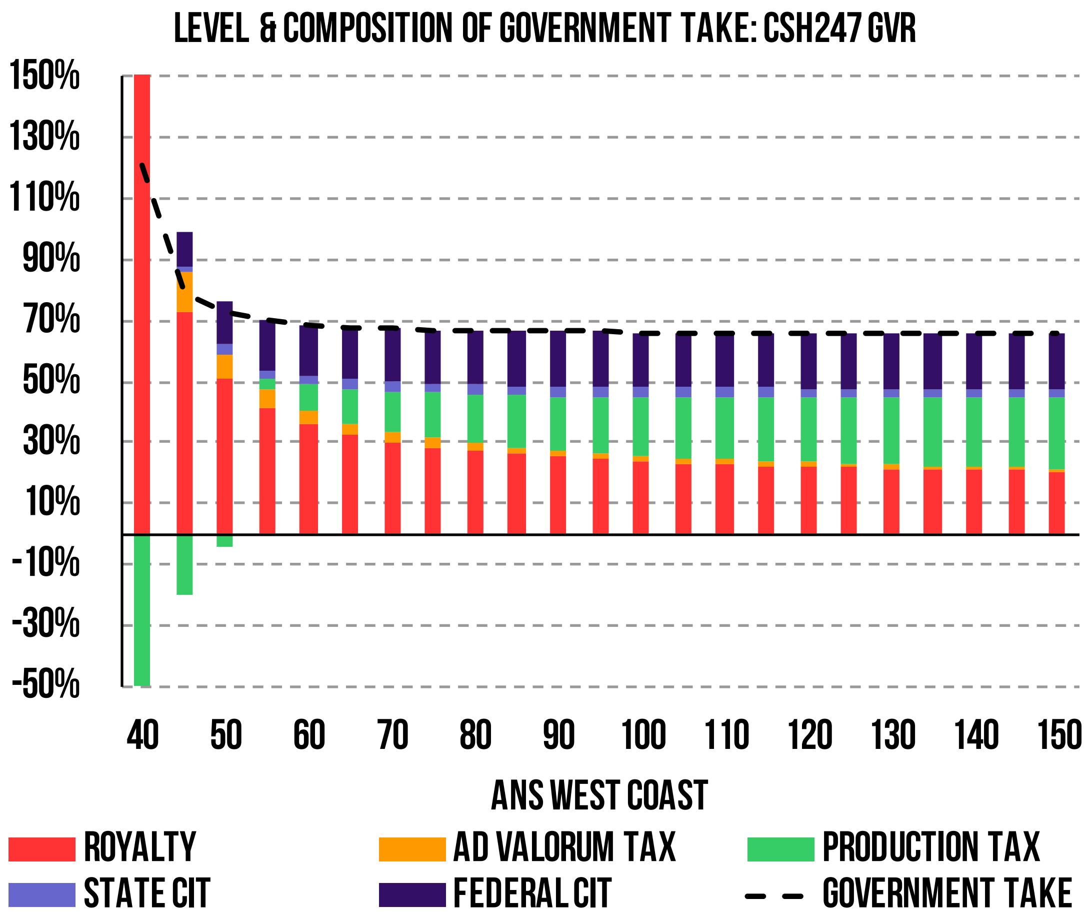
FLOOR HARDENING MAKES TAX SYSTEM MORE REGRESSIVE

State of Alaska making negative production tax in today's prices; but overall gov't take is still high

Impact of floor hardening is to shift up government take in lower oil prices

In times of high investment / low prices (as in 2016), effective government take exceeds 100%





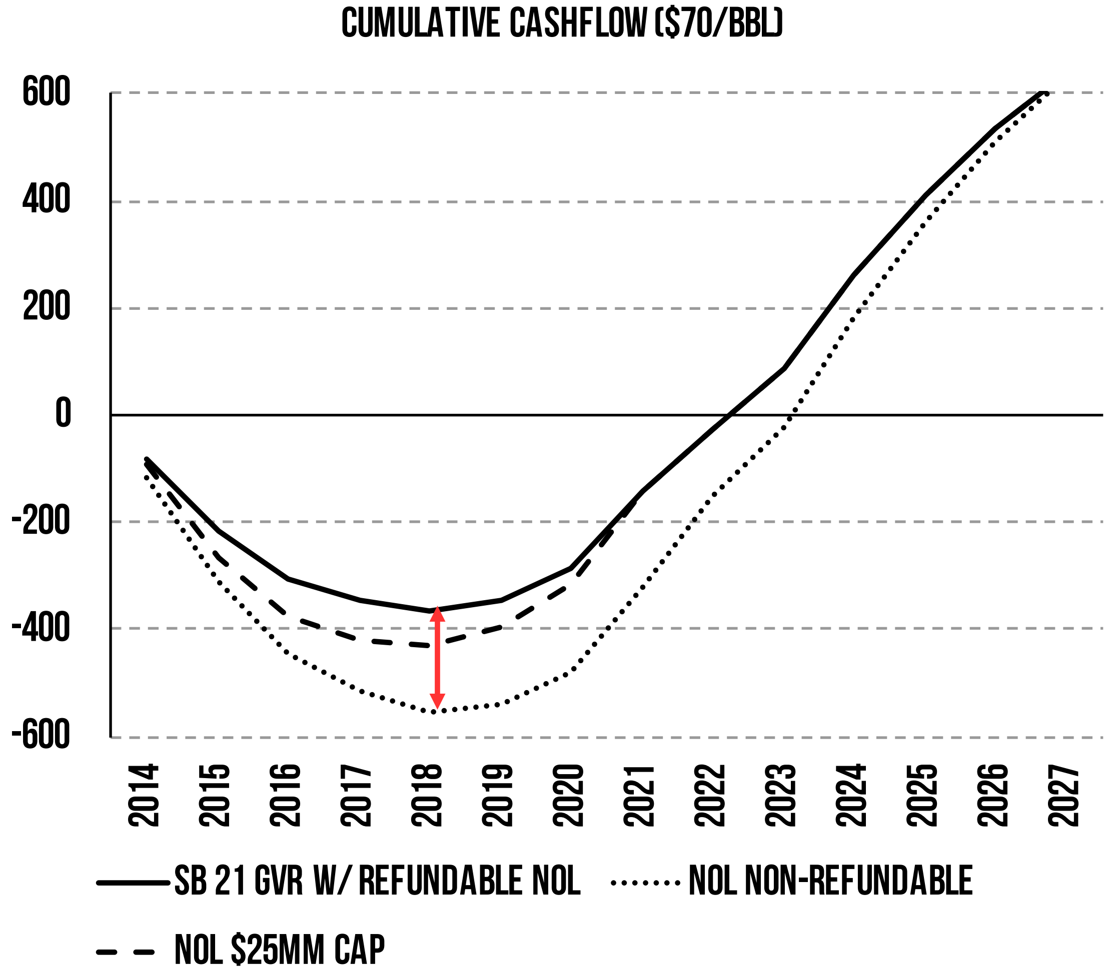
REFUND LIMITS BOOST CAPITAL NEEDS AND LOWER IRR

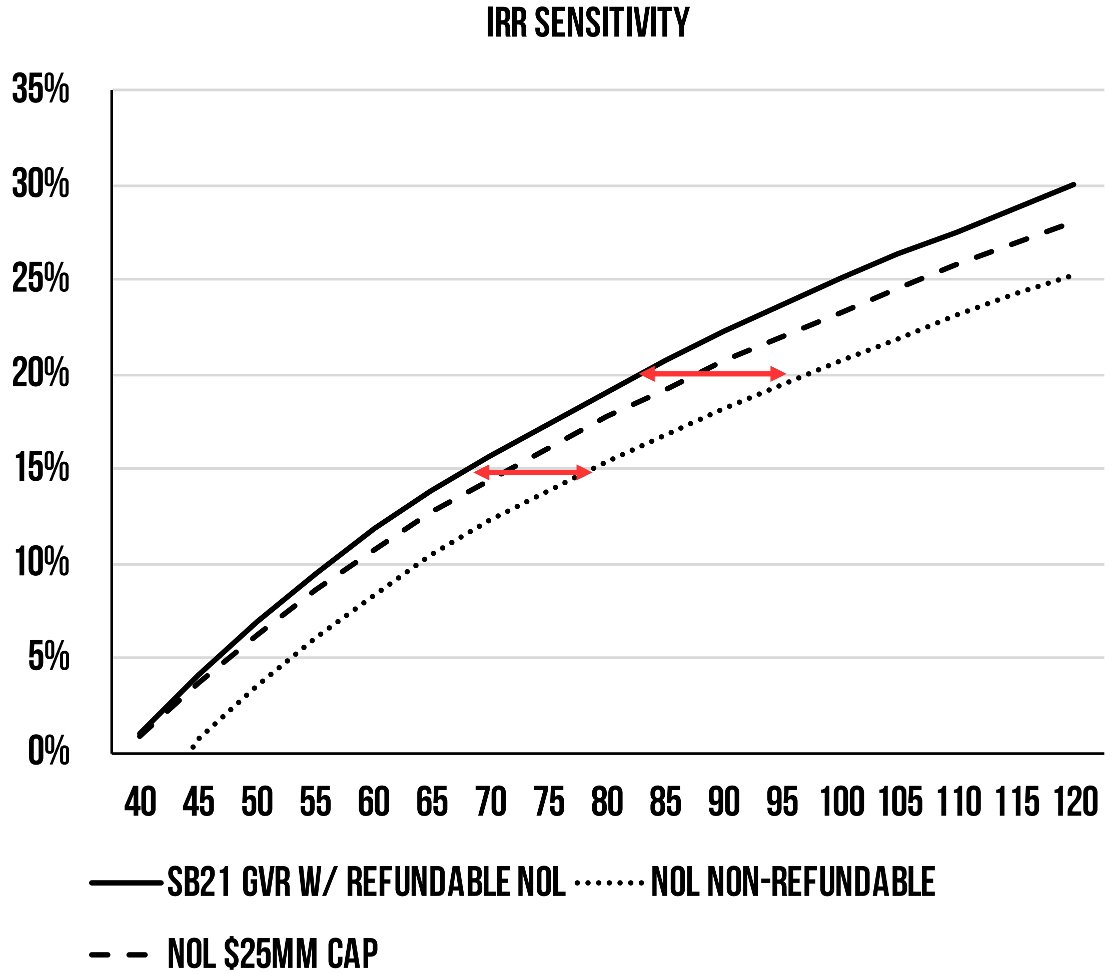
Refundable credit limit would **increase capital needs** by up to 50% (from $350mm to $400–$550mm)

Application to projects currently under development could have **major adverse impacts**

Near-Kuparak-sized new development could easily incur >**$2bn in NOL credits** in development years

If per-company limit on refundability is the solution, what is the right level? $100mm? $85mm?





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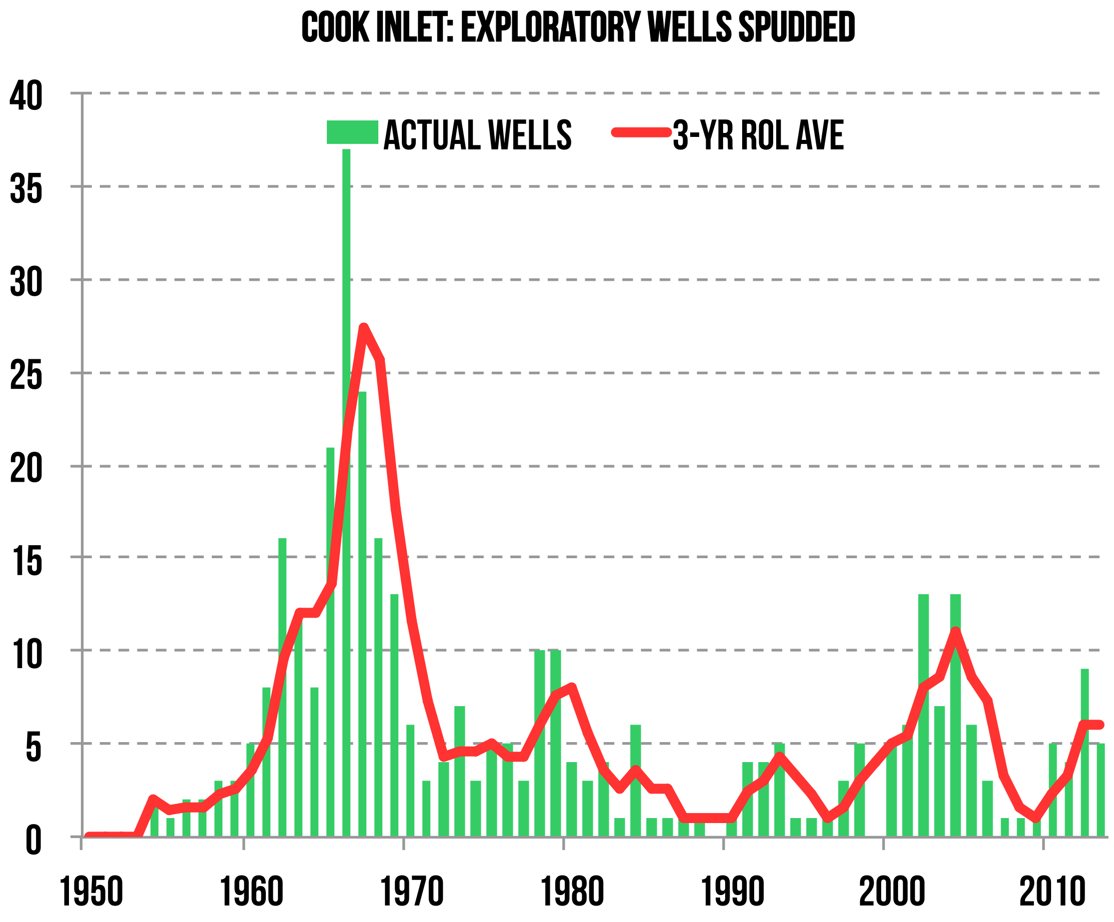
ACTIVITY HAS RESPONDED IN RECENT YEARS

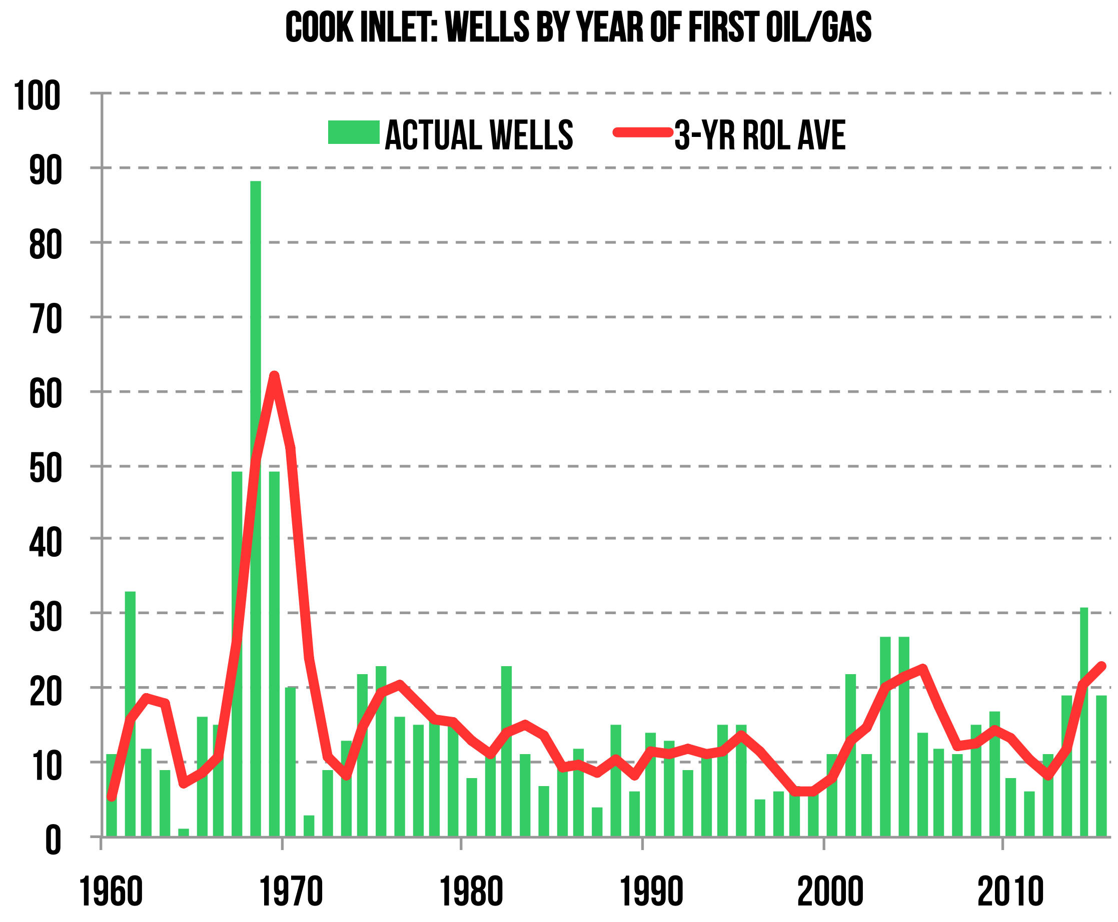
Exploration drilling in Cook Inlet has gone through several cycles since 1950s

Recent exploration activity (post 2010) on par with previous exploration peaks

Development drilling has been more stable over the years

Recent growth placing three-year rolling average among highest in state's history

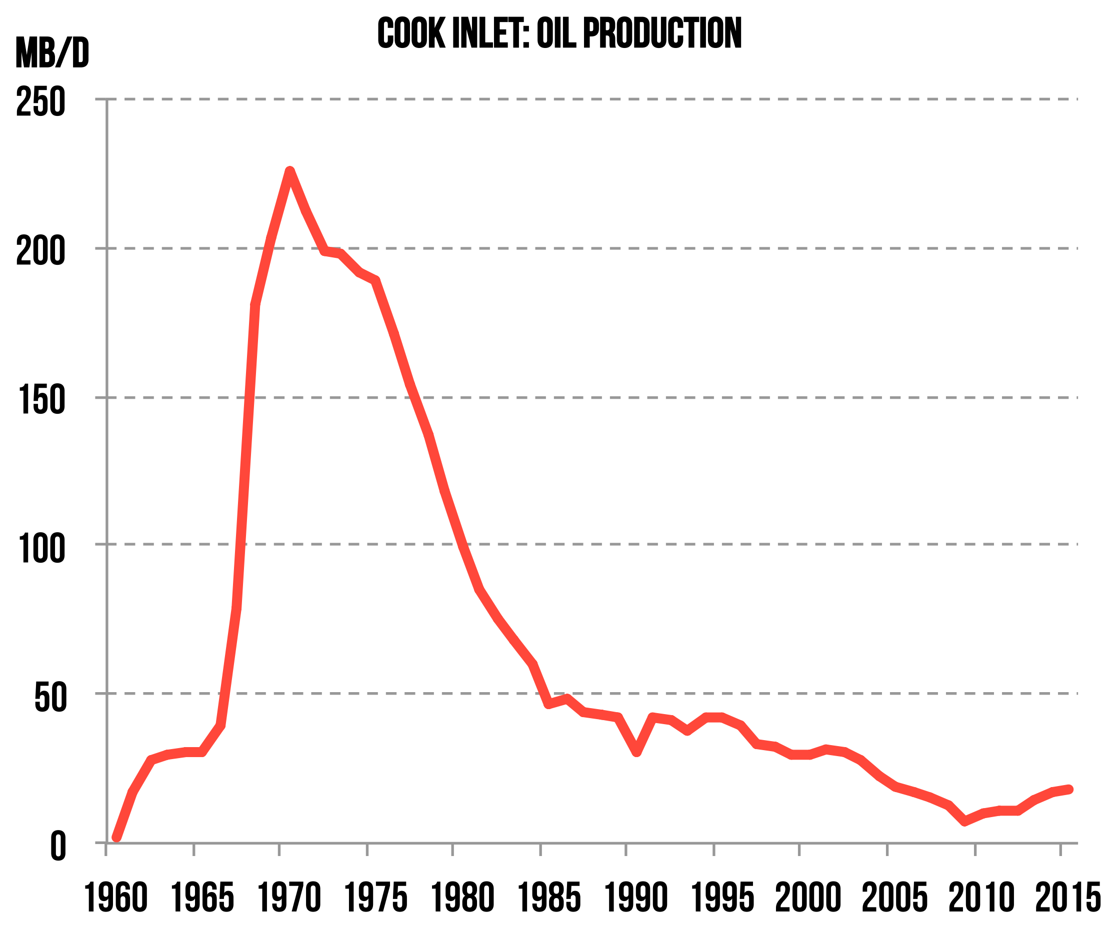


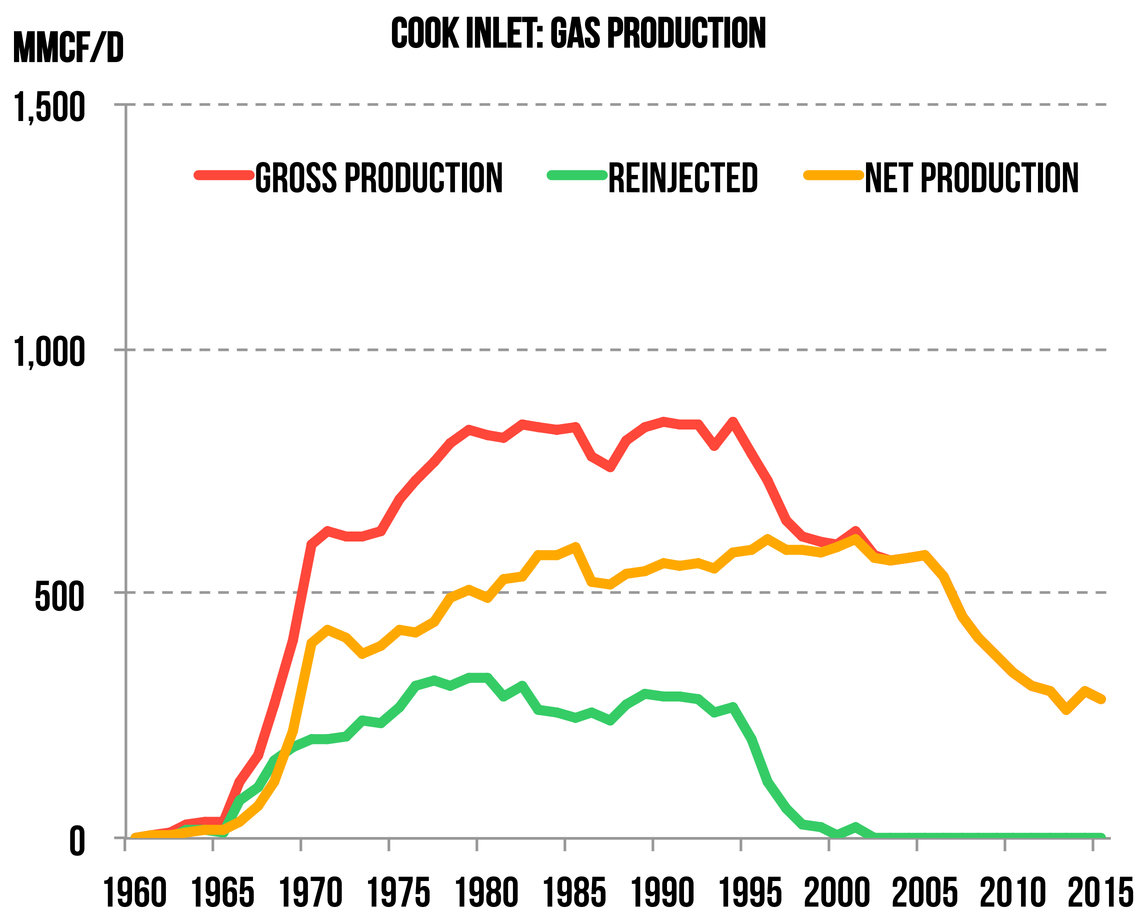


SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

COOK INLET OIL AND GAS PRODUCTION: BASIC FACTS

Oil	Peak in 1970 at 226 mb/d; trough in 2009 at 7.5 mb/d; upturn post 2010 (+10.5 mb/d)
Gross Gas	Peak in 1990 at 853 mmcf/d; big drops in 1994–1998 and 2005–2013; stable in 2014–15
Net Gas	Peak in 1996; 1990s plateau from blowdown at Swanson River; fall post 2005, then stable





SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

THE COOK INLET OIL AND GAS MARKET: A SCORECARD

What has happened to oil and gas production and activity in the Cook Inlet in recent years?

Oil production has risen from 7.5 mb/d in 2009 to almost 18 mb/d

Gas production has stabilized after years of steadier decline

How has the gas market adjusted in recent years?

Cook Inlet has undergone major transition in supply, demand, prices, competition and expectations

Some of these changes are typical in mature basins—others are unique to Cook Inlet

What's the outlook and how sensitive is the outlook to changes in oil/gas fiscal system?

DNR: 1,183 bcf in remaining 2P reserves; 1,600 bcf w/ Cosmopolitan and Kitchen Lights (ballpark)

Continued drilling at old fields plus Cosmopolitan and Kitchen Lights: current market well supplied

At current (gas) price levels, brownfield investment should be profitable under stricter fiscal regime

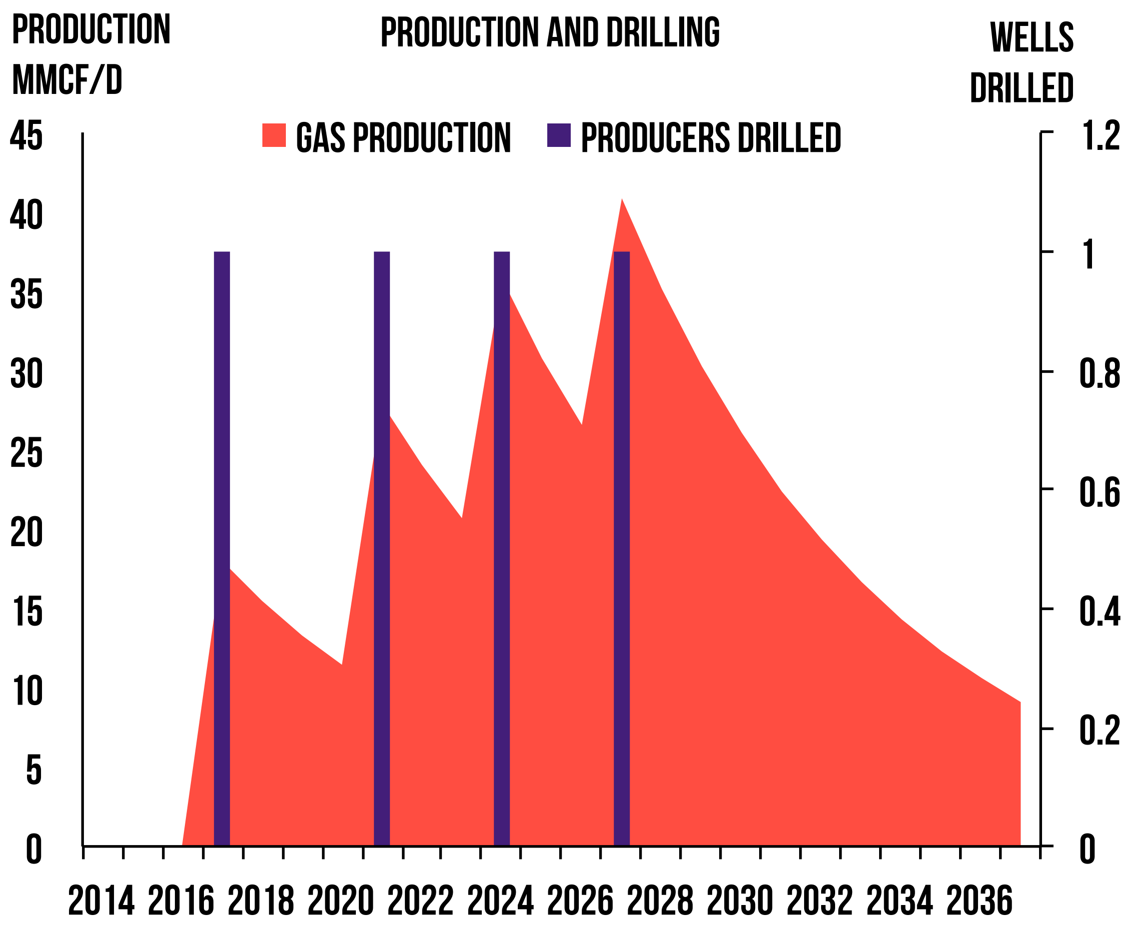
Credits more important for developing new resources, especially with demand constraints

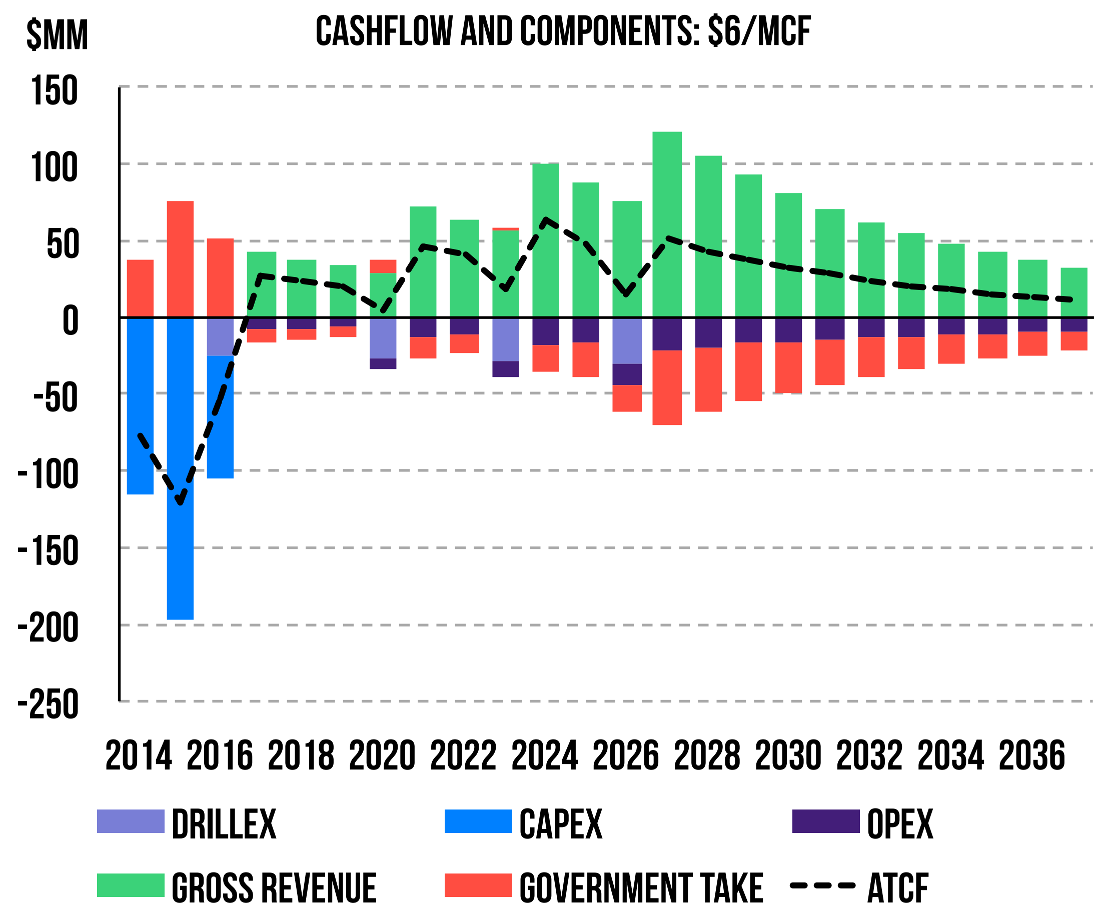
Currently much uncertainty over future regime - setting a stable, sustainable system is paramount

PROJECT #1: MARKET CONSTRAINED (ASSUMPTIONS)

Large upfront investment but constrained gas market

Limited ability to sell gas: can only drill a well every few years





PROJECT #1: MARKET CONSTRAINED (RESULTS)

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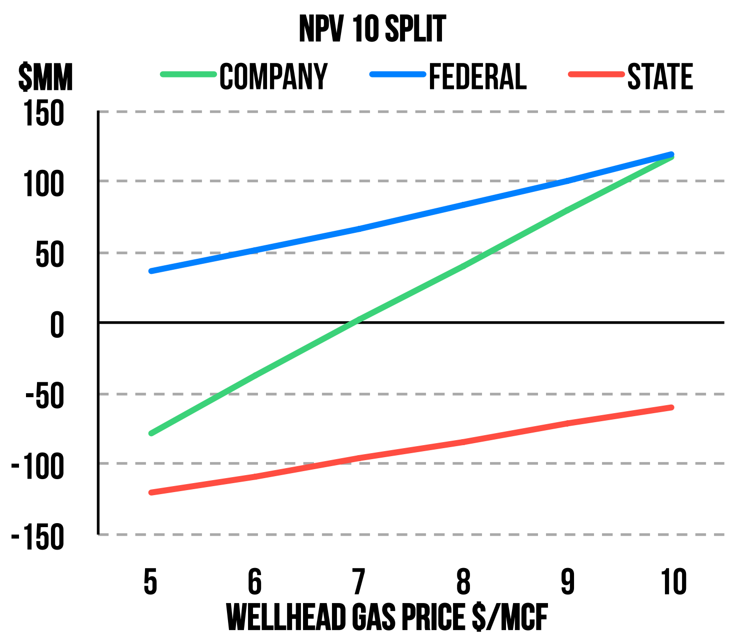

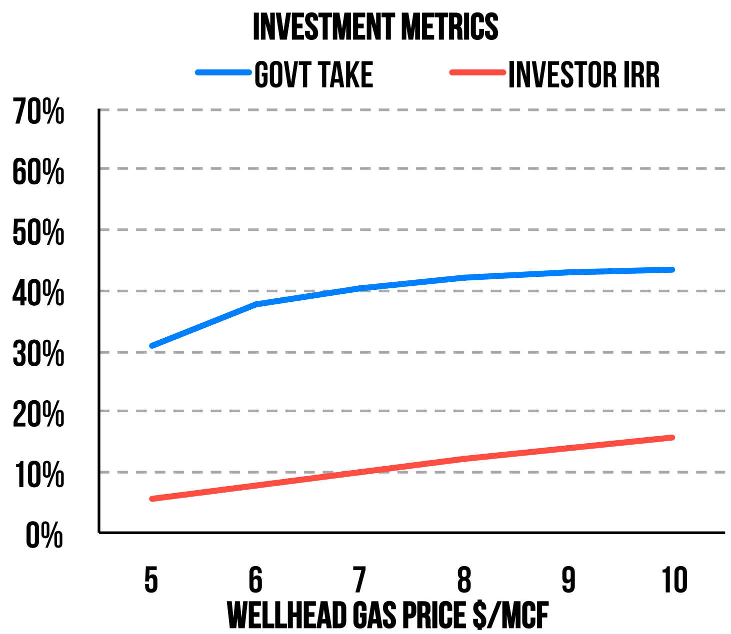

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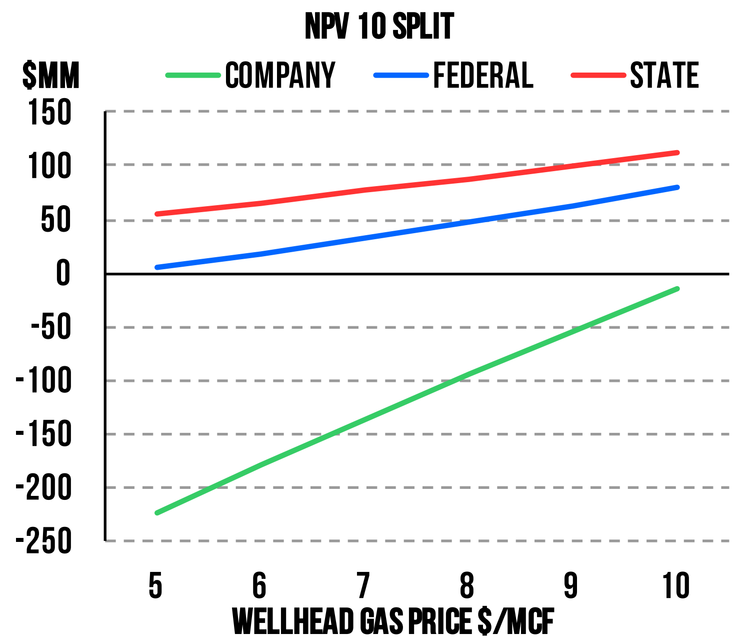

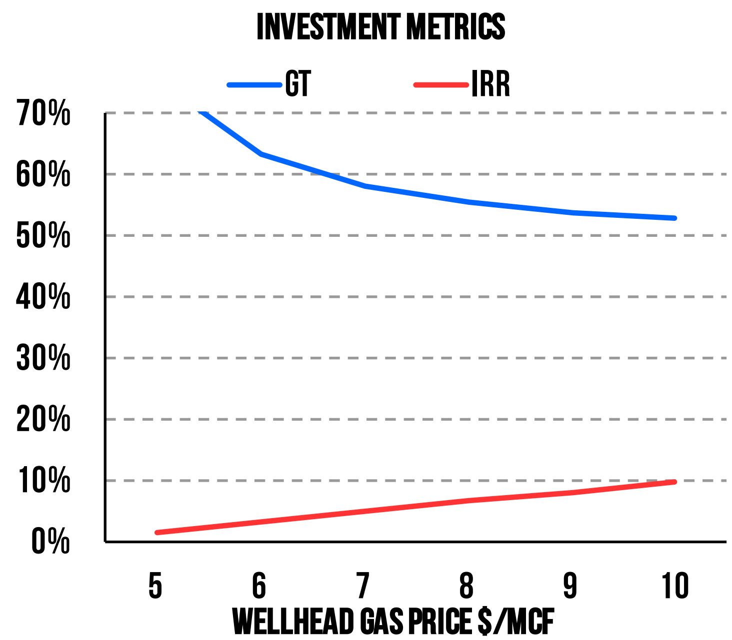

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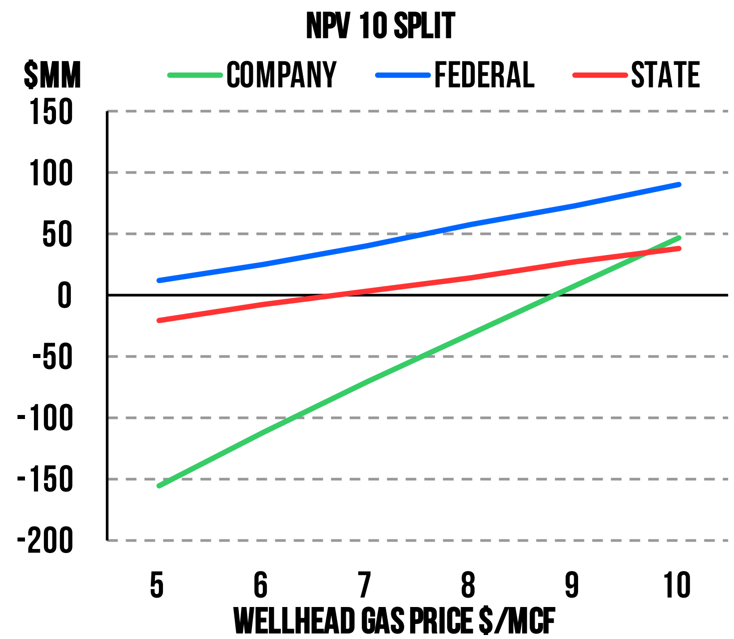
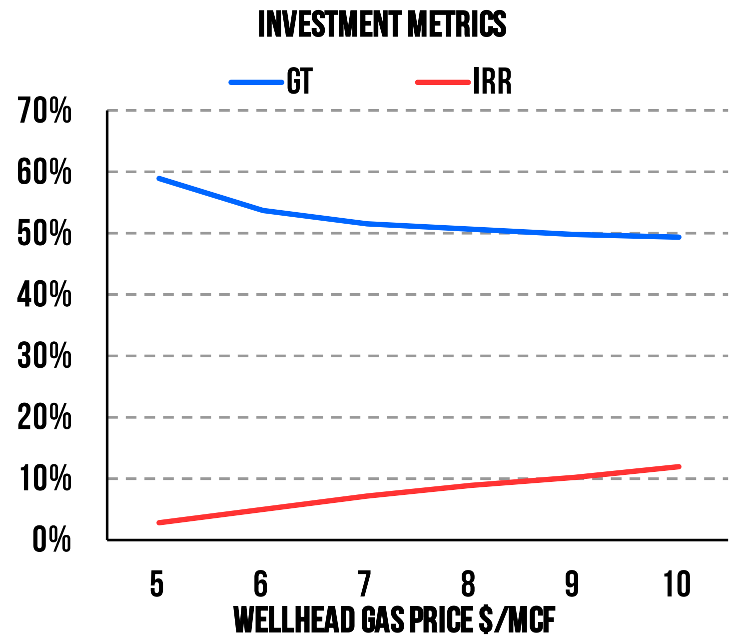


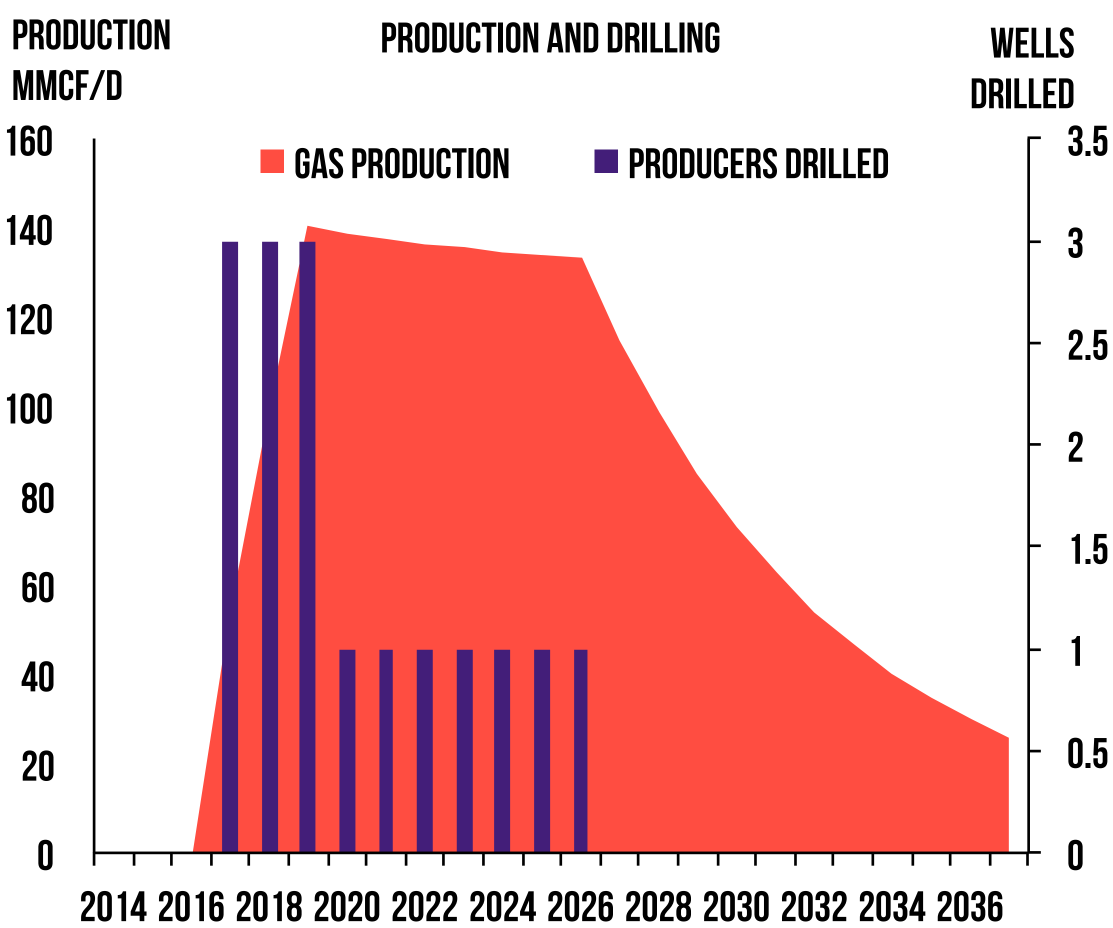


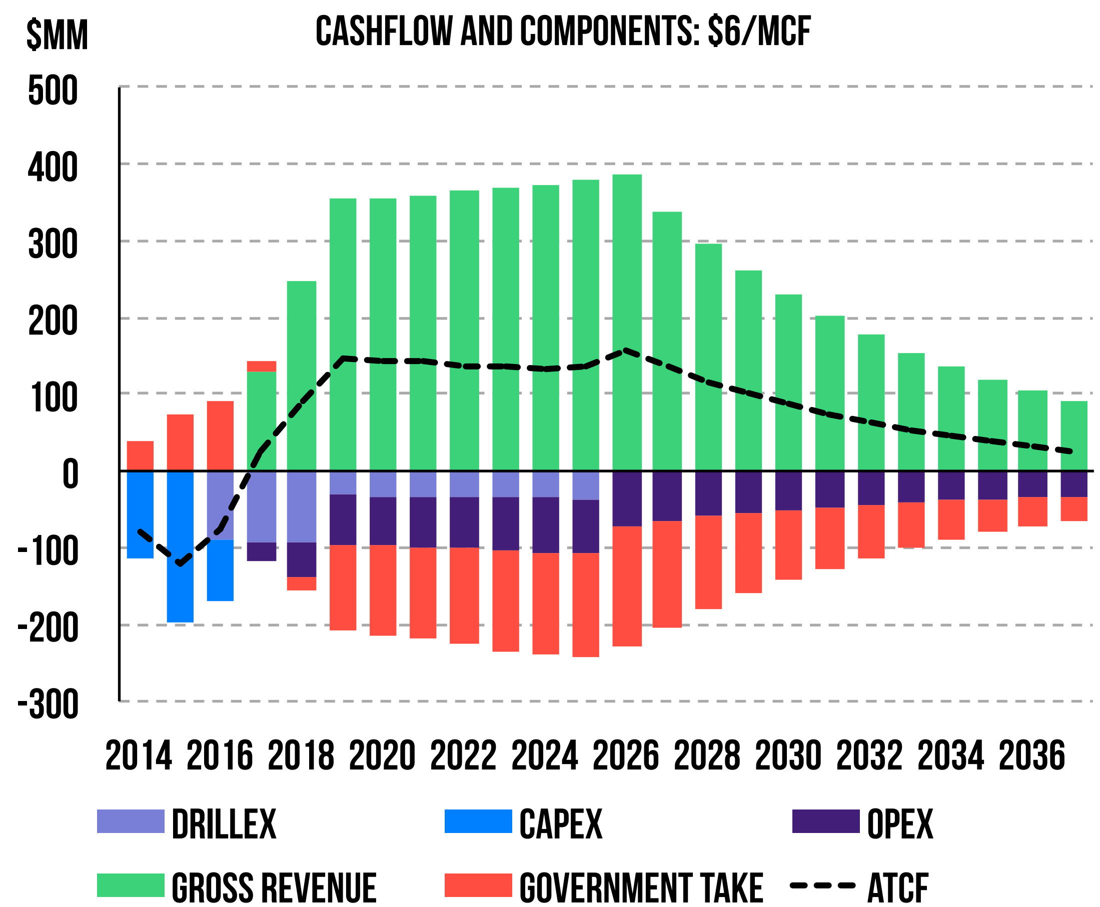
PROJECT #2: MARKET UN-CONSTRAINED (ASSUMPTIONS)

Large upfront investment but un-constrained gas market

Continued drilling lead to a plateau of 130 mmcf/d

Scenario would require a step change in existing supply-demand dynamics in Cook Inlet





PROJECT #2: UN-CONSTRAINED (RESULTS)

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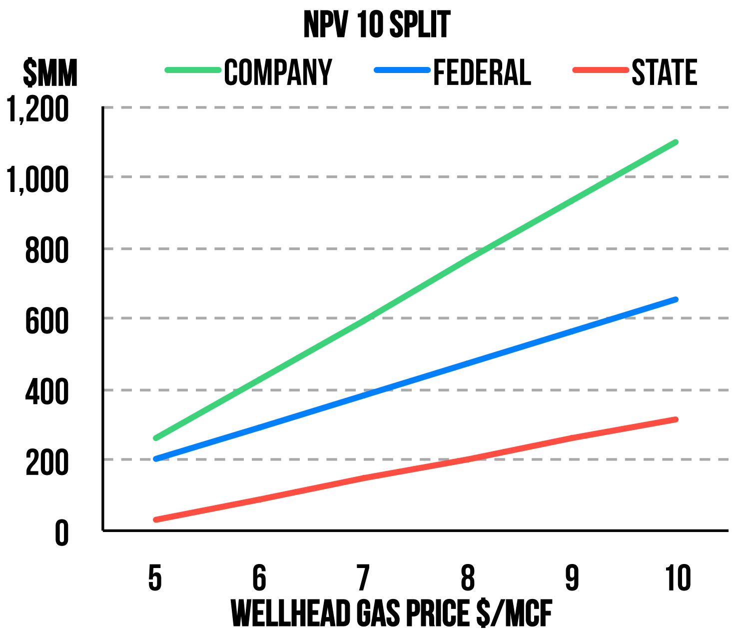

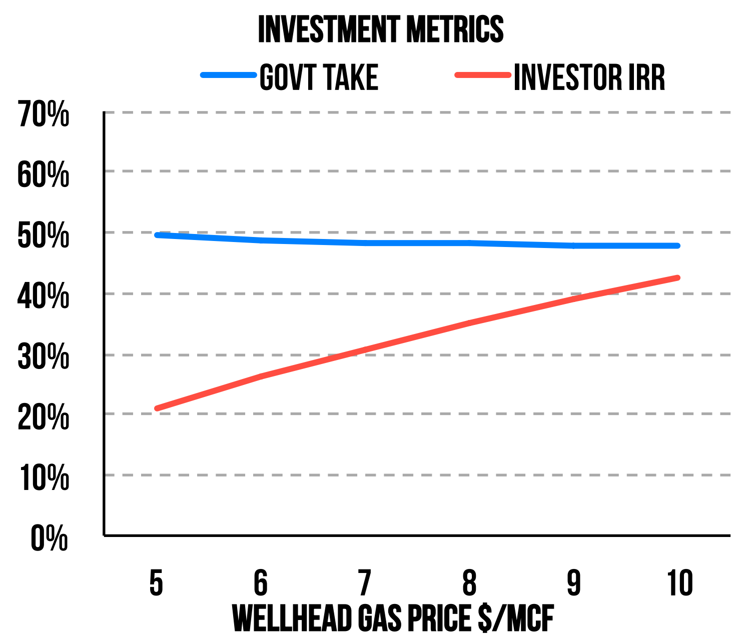

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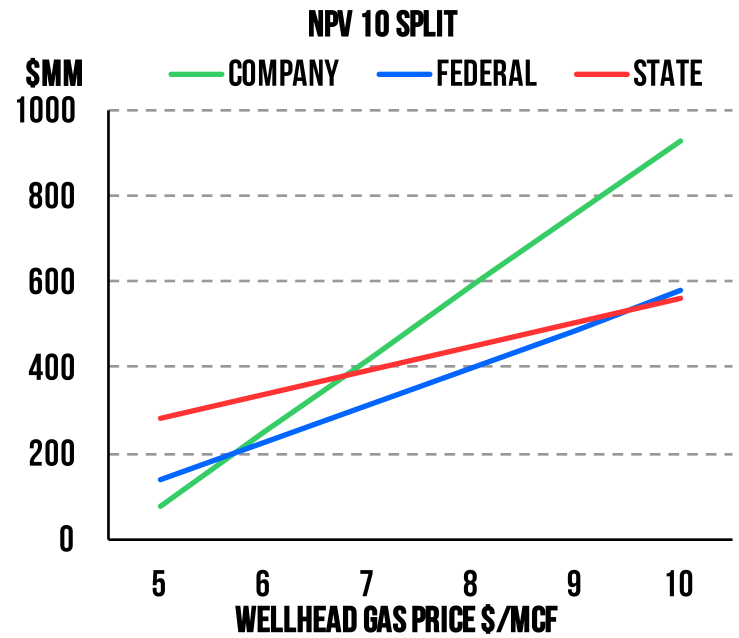

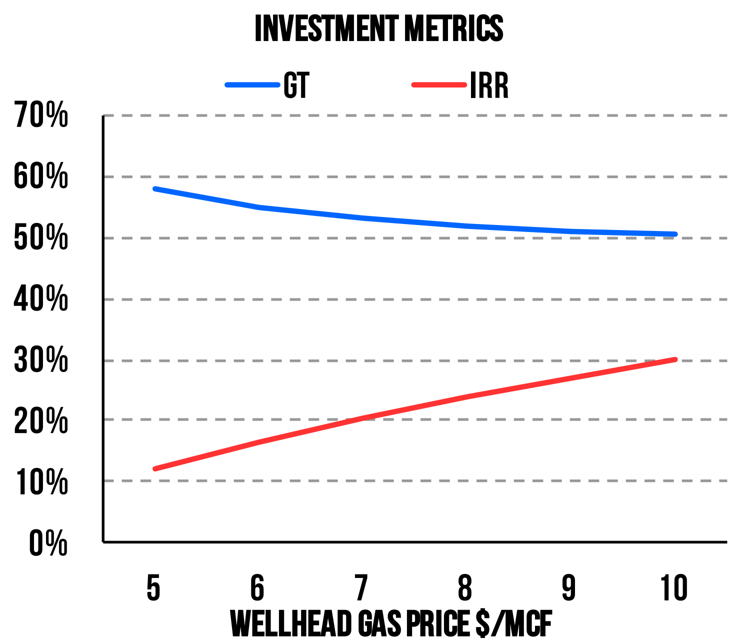

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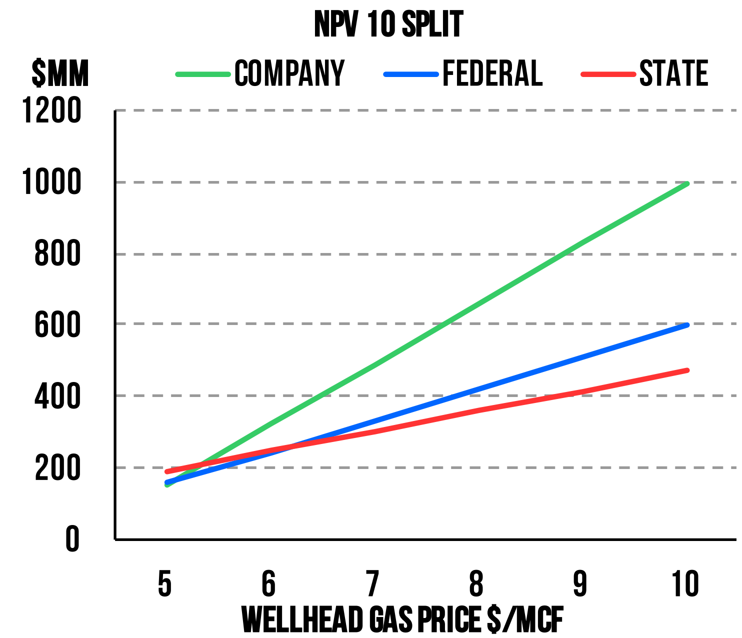
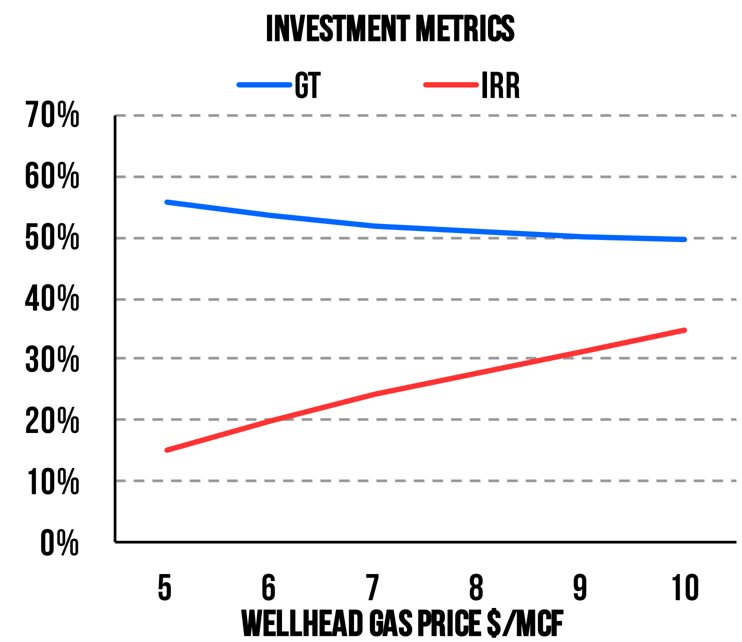


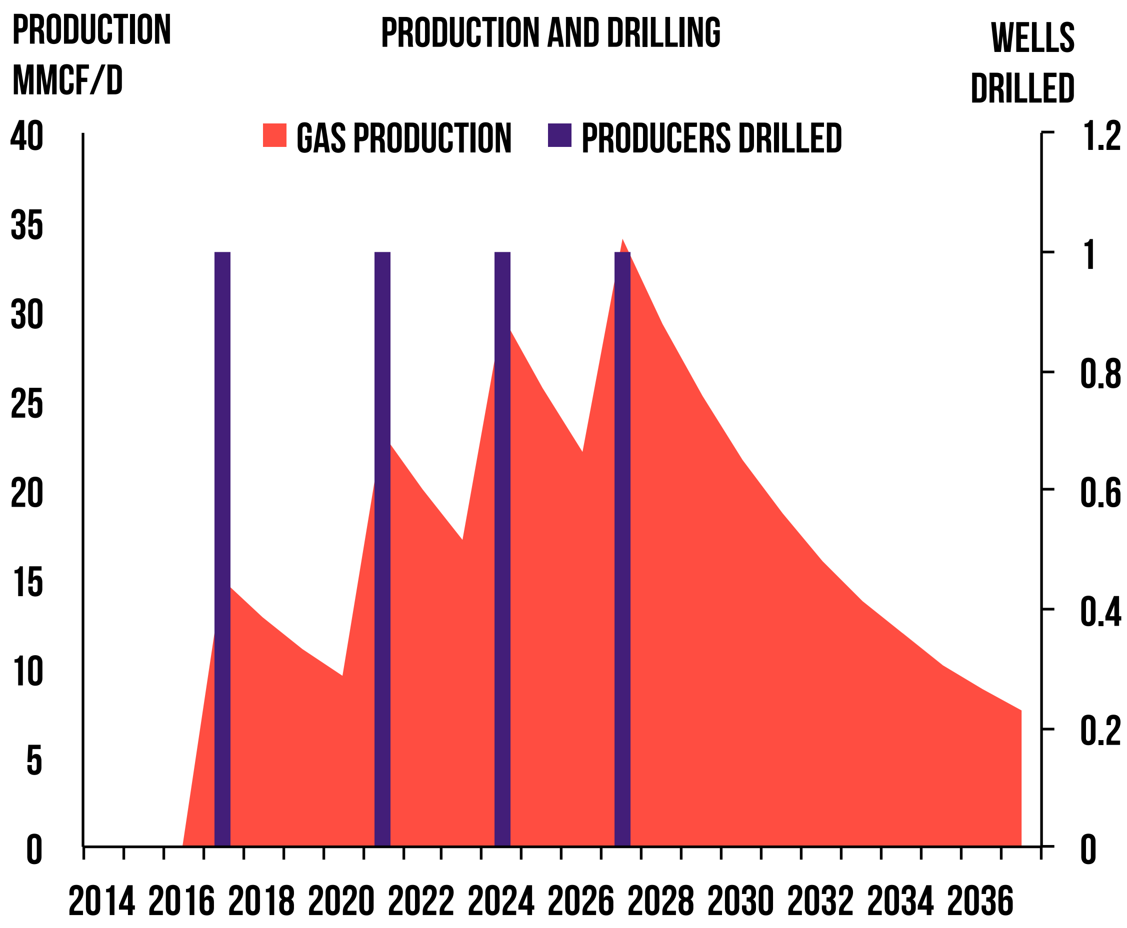


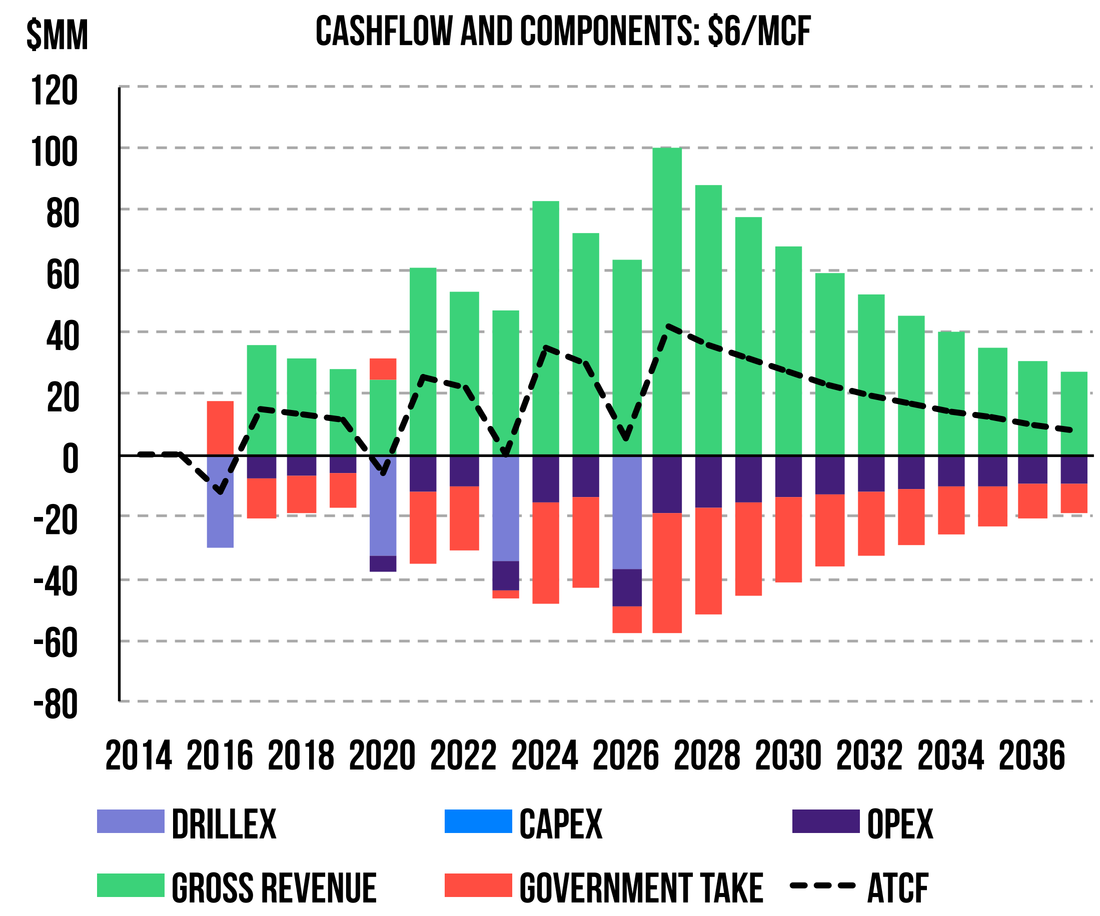
PROJECT #3: DRILLING IN EXISTING FIELD (ASSUMPTIONS)

Drilling expenditures at existing production—smaller upfront investment

No market constrains assumed

This is a point-forward analysis—it ignores sunk, entry or acquisition costs





PROJECT #3: DRILLING EXISTING FIELD (RESULTS)

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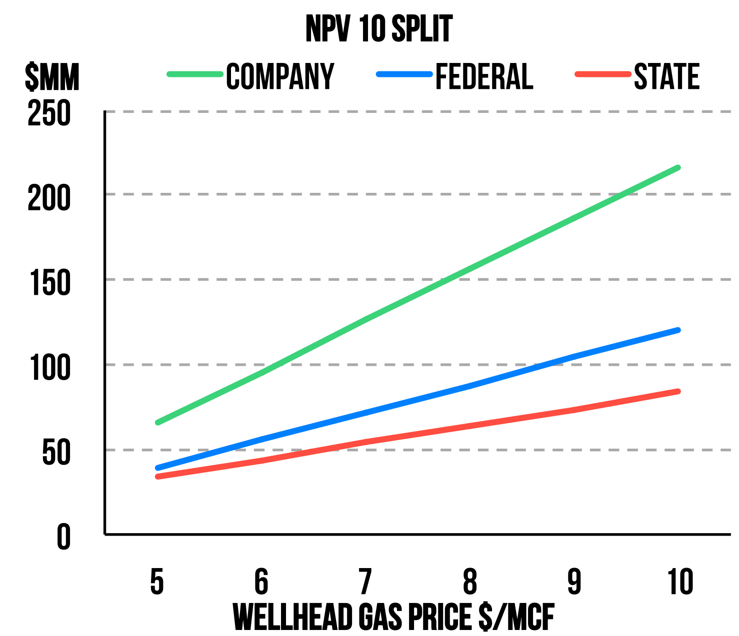
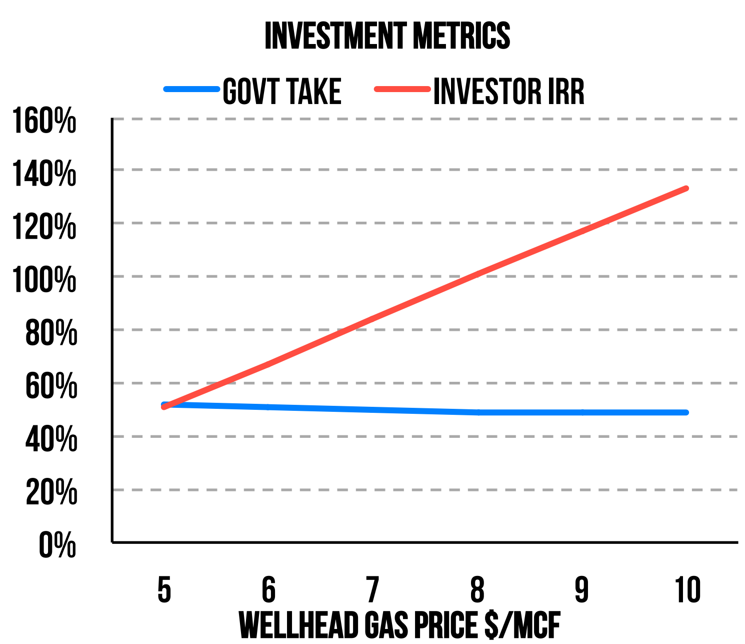
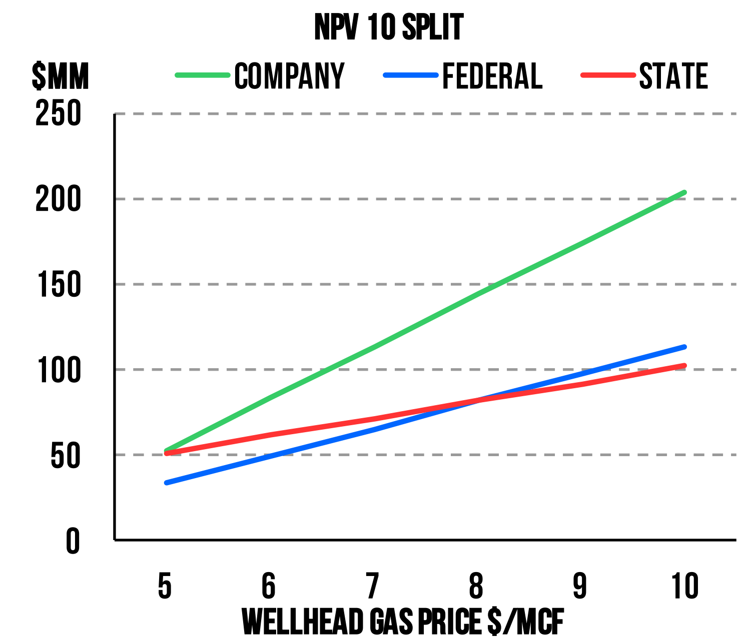
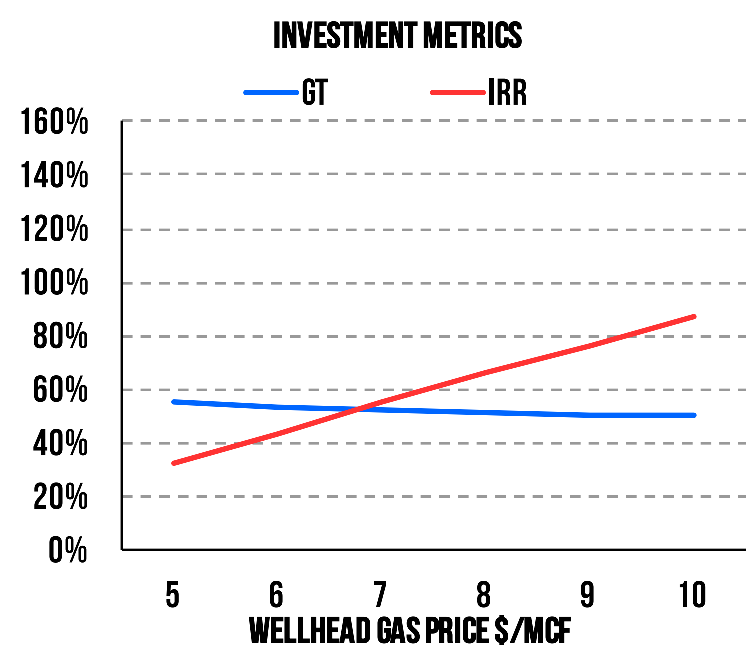




CS SB 130 (RES)





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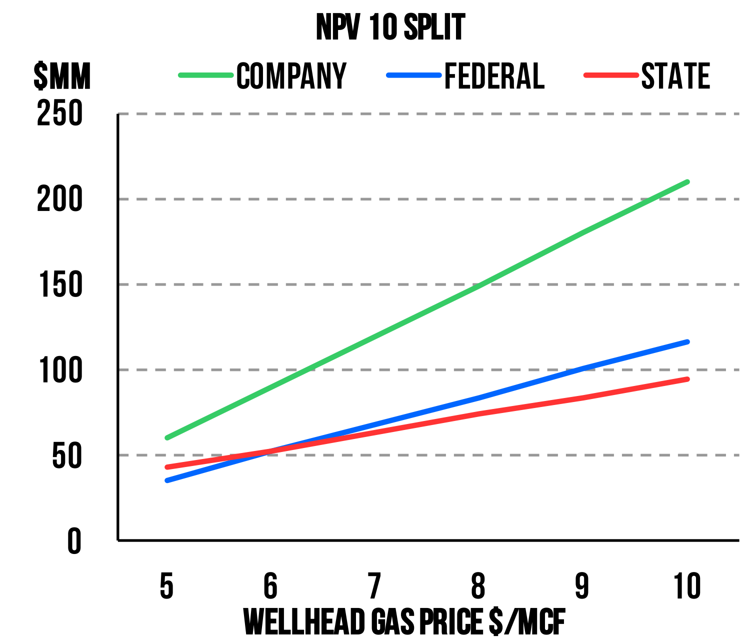
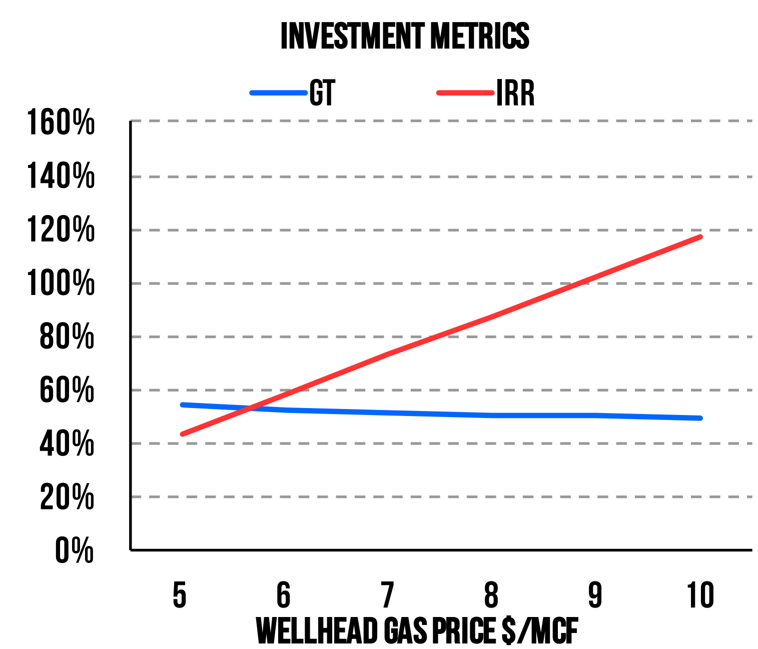




AGENDA

Issue	Status Quo	CS HB 247 (FIN) / CS SB 130 (RES)	Impact
Gross value reduction and net operating loss credit	Because GVR artificially reduces Production Tax Value, 35% NOL credit can be claimed on amount greater than actual loss - more than 35% support for spending.	Assess NOL credit on actual loss (not including GVR), so NOL is for 35% of actual loss, and all producers have 35% support for spending.	Make North Slope state support for spending uniform at 35%. Interaction is arguably an unintended consequence under SB21, though fixing has negative impact for current GVR new developments.
Time limit on gross value reduction	No current time limit on how long new developments benefit from GVR.	Allow GVR benefit only for 5 years from first production (or until 1/1/2021).	Short limit effectively eliminates much of the GVR benefit. Major negative impact on recently sanctioned eligible developments.
Refundable credit withholding	Liabilities against production tax withheld from refundable credits, but not other liabilities.	Any exploration/development/production related liabilities to the state can be withheld from refundable credit payments.	Companies in dispute over liabilities will have those amounts withheld. Companies that wish to have withholding used to settle liability may do so.
.025 'Middle Earth' exploration credit	$25 mm or 80% credit, sunsets July 1 2016.	Extend to allow for completion of wells spudded before July 1.	
Municipal production expense deduction	Munis that own production and only sell portion can deduct all expenses and claim credits.	Credits and deductions can only be claimed in proportion to taxable production.	
Surety bond	No bond requirement.	Add $250,000 bond as license requirement.	

Issue	Status Quo	CS HB 247 (FIN)	CS SB 130 (RES)	Impact
Cook Inlet Tax credits & fiscal system	25% Net Operating Loss credit, 20% Qualified Capital Expenditure credit, 40% Well Lease Expenditure credit; up to 65% gov't support for spending and minimal production tax.	Reduce NOL credit to 10%, QCE to 10%, WLE to 20% by 2018. Restrict eligibility for NOL. Working group on Cook Inlet regime.	Reduce NOL credit to 15%, QCE to 10%, WLE to 20% by 2017. No Credits and no production tax from 2018 Onward.	Cook Inlet credit regime is clearly unsustainable in current environment; degree of ramp-down / elimination has fiscal-note impact, but also potential impacts on future investment.
North Slope gross minimum tax	4% rate, binding for legacy output if net value is positive. If net value is negative, NOL can 'pierce' floor. "New," GVR-eligible production can take to zero due to $5/bbl and small producer credit.	Introduce additional, 'harder' 2% gross floor; no credits can reduce tax liability below this.	Maintain status quo - no further floor hardening.	Hardening has high fiscal-note impact, but most is revenue brought forward from future (NOL), not truly additional. Makes regressive system more so, and adds strain to cashflow-negative companies.
Refundable credit cap	Producers with >50 mb/d production must carry NOL forward, others can be reimbursed by the state. Major new NS development could place significant strain on state cashflow.	$100mm per company annual limit on reimbursement.	$85mm per company annual limit on reimbursement.	Low limit substantially increases capital needs for new developments & raises hurdle rates/break-even prices. $100mm likely not binding on companies now given current spending plans; $85mm may have negative impact on some.

Feature	Status Quo	CS HB 247 (FIN)	CS SB 130 (RES)	Impact
'Middle Earth' credits	25% Net Operating Loss credit, 20% Qualified Capital Expenditure credit, 40% Well Lease Expenditure credit.	Maintain NOL at 25%, reduce QCE to 10%, WLE to 30% by 2018. WLE may sunset in 2019?	Reduce NOL credit to 15%, QCE to 10%, WLE to 20% by 2017.	Fiscal impact of 'Middle Earth' credits currently minimal, but questions about capital credits may arise if significant development occurs.
Interest due on 'delinquent' taxes	Fed Discount Rate + 3% Simple Interest on delinquent taxes (up to 6-year audit statute of limitations).	Fed + 5% compounded quarterly for 3 yrs, then Fed + 5% simple interest (up to 6-year audit statute of limitations)	Fed + 7% compounded quarterly for 3 yrs, then no interest (up to 6-year audit statute of limitations)	Current simple interest arguably a drafting oversight from SB21 debate. Core issues here determine 'fair' rate vs companies' concerns over impact of long audit backlog on interest bills when interest rate is higher and compounded.
Alaska hire	Alaska hire not currently given preferential treatment in tax code (significant constitutional restrictions).	No change	No preferential treatment in amount of refunded credits, but companies with >75% Alaska hire placed higher in queue for refundable credit payments	

AGENDA

CS SB130: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

CS SB 130: SUMMARY OF KEY ISSUES

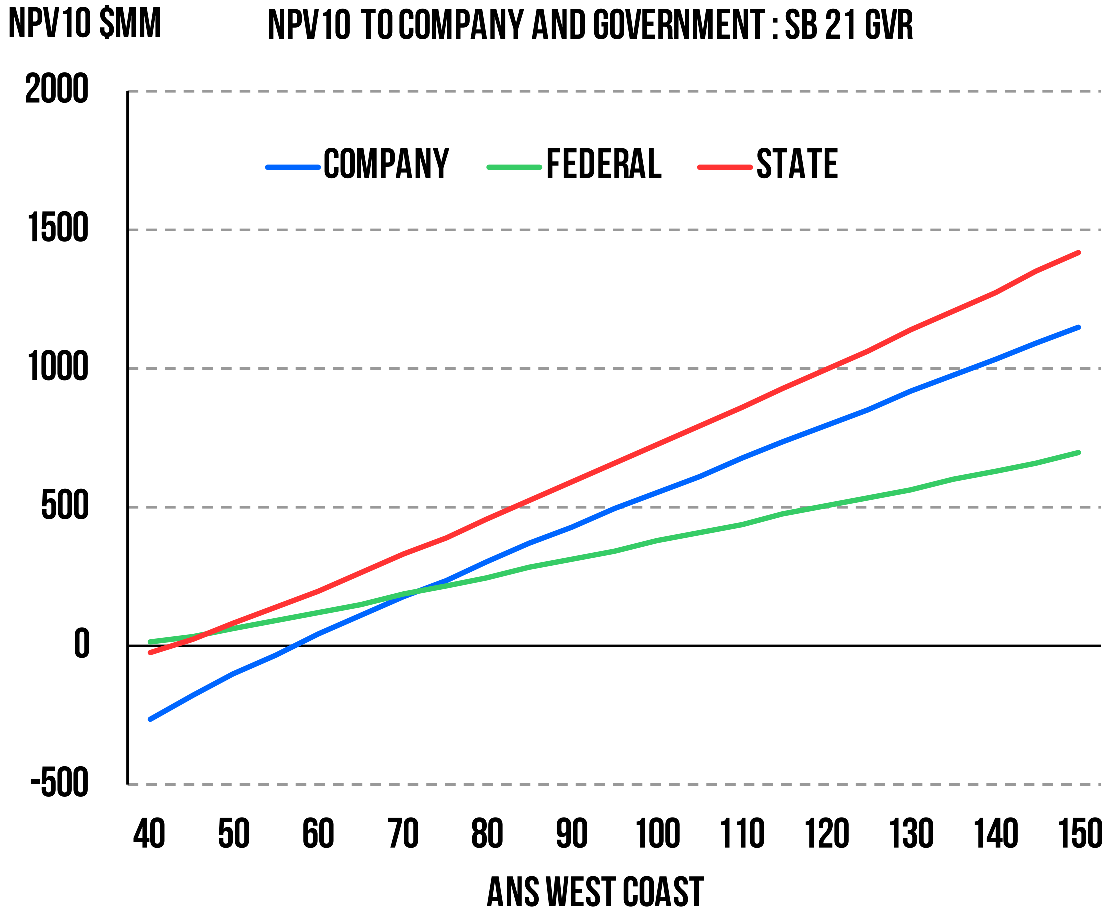
APPENDIX

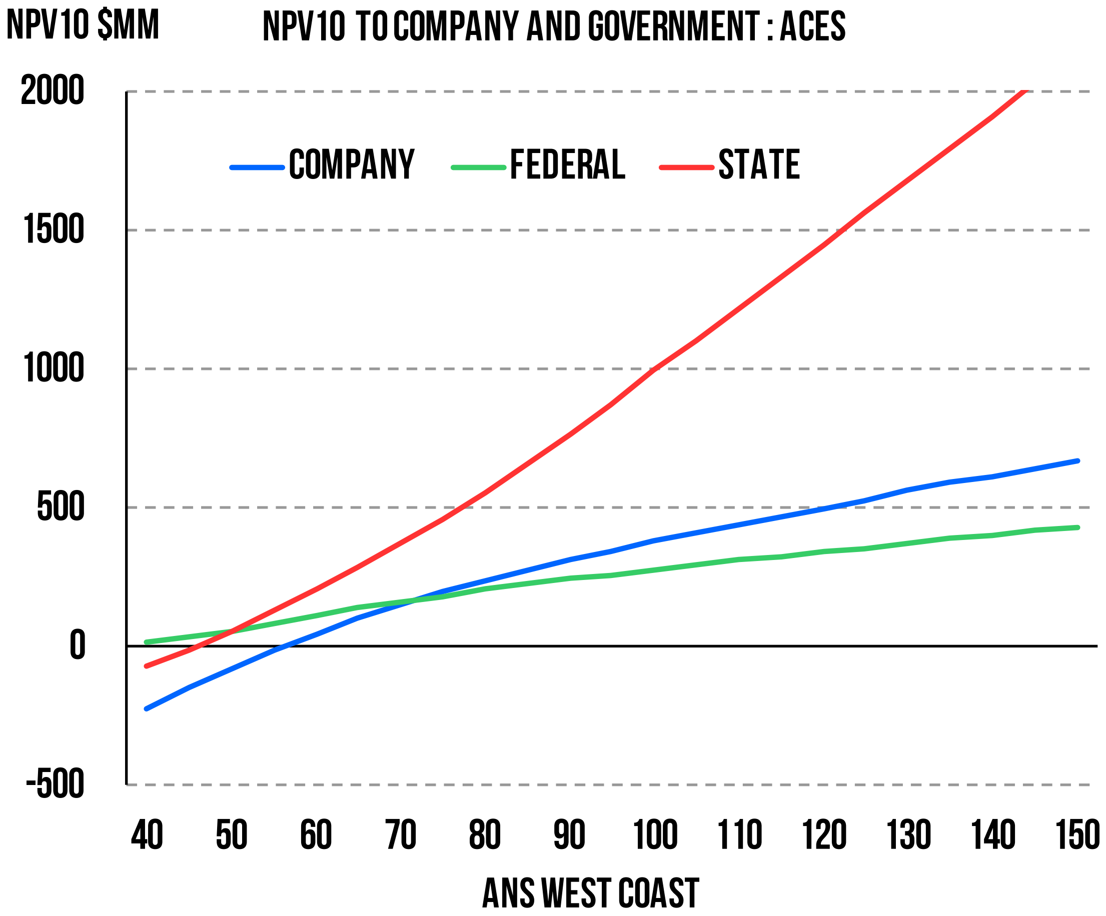
SB21 WITH GVR: VALUE SPLIT

Using sample NS investment, examining total value over lifecycle to all stakeholders at range of prices:

- SB21 GVR Split of total value between state and company relatively even over a wide range of prices

- SB21 GVR state NPV10 higher than that for company at all prices, and at low prices, higher than ACES





COOK INLET GAS HAS GONE THROUGH MAJOR TRANSITION

Old Cook Inlet Gas Market	New Cook Inlet Gas Market
Surplus gas exported (via LNG and Agrium)	Limited surplus; gas absorbed in local market
Low wellhead prices	High wellhead prices
Market view is that gas is long	Market view is that gas is short
Gas produced by large, international players	Gas produced by smaller, focused players
Secure local supply via long-term contracts	Shorter term sales contracts b/w producers, utilities
Producers offered high seasonal flex	Mature fields have much more limited seasonal flex
Seasonal flex coming largely from supply	Seasonal flex largely from storage and demand

GAS SUPPLY AND DEMAND DYNAMICS IN COOK INLET

Supply and resources

2015 production: 103 bcf

Estimated 2P reserves: 1,600 bcf (DNR, 2015)

- Legacy fields: 1,183 bcf
- Kitchen Lights/Cosmo: 417 bcf (ballpark)

Yet to find estimates are much higher

Demand

2015 consumption around 100 bcf

- In-state demand: 80-85 bcf/yr
- Exports: 13–16 bcf (2014–2015)

AGDC 2030 forecast: 115 to 130 bcf/yr (ex. nitrogen)

Nitrogen demand upside: 28 bcf/yr per train (2 trains)

Existing + new fields should be enough for current demand 10+ years; demand upside needs more gas

State support due to gas "shortage," yet developers say they lack markets to develop new fields; why?

- Maybe issue is timing (market covered by existing contracts, window opens later)
- Or a natural negotiation process (buyers and sellers looking for the "right" pricing point)
- Or different views about resource certainty, especially for developing new demand (Agrium)

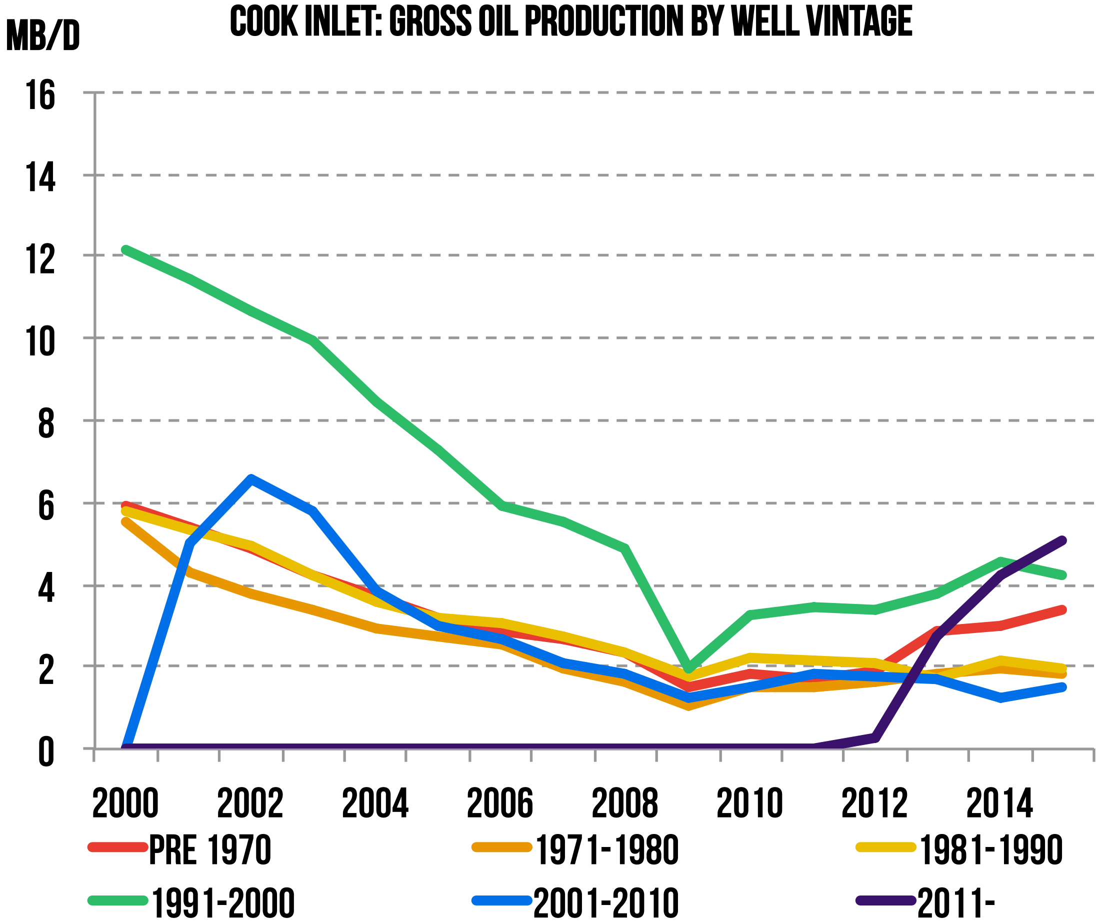
SOURCE: DEPARTMENT OF NATURAL RESOURCES; ALASKA OIL AND GAS CONSERVATION COMMISSION; ALASKA GASLINE DEVELOPMENT CORPORATION; MCDOWELL GROUP (NITROGEN DEMAND)

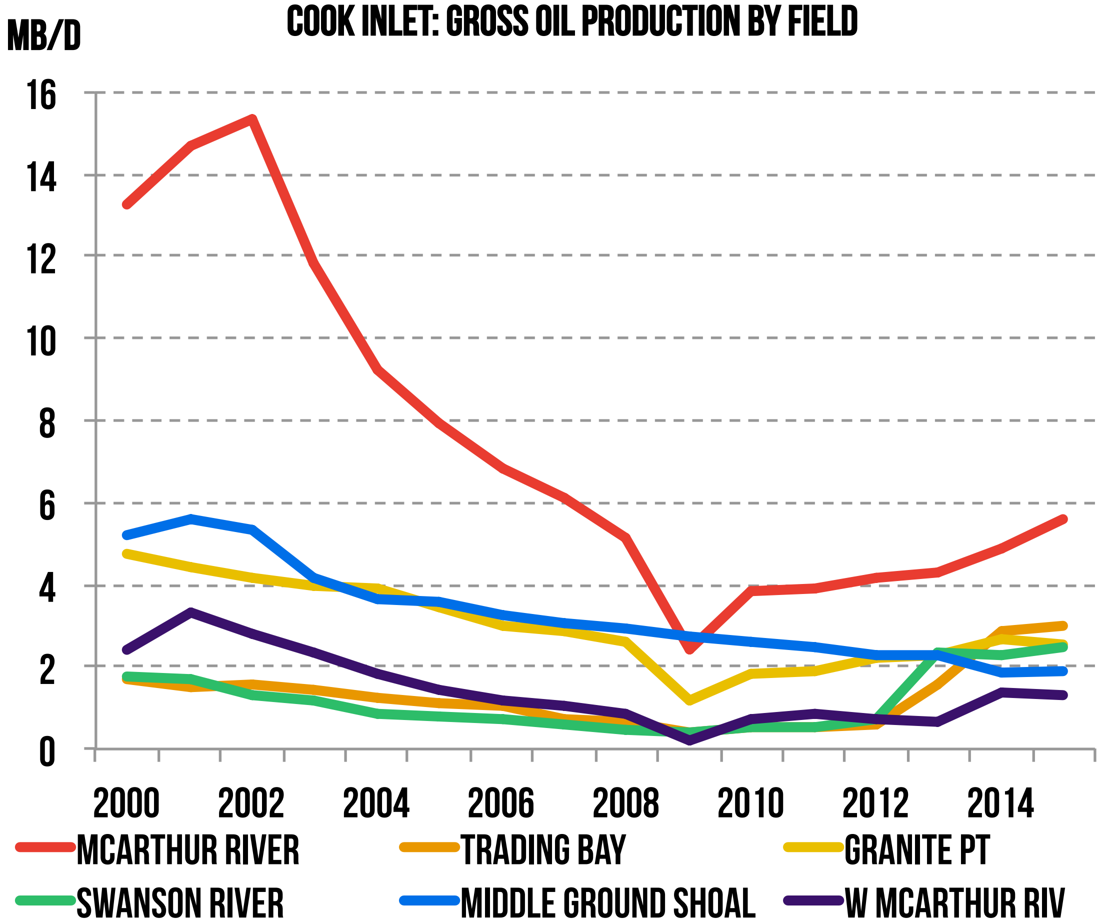
OIL UP FROM WORKOVERS, NEW WELLS IN EXISTING FIELDS

Production from old wells has risen, especially from wells drilled before 1970 and in 1990s

New wells drilled after 2011 have also added about 5 mb/d of production

Production is up in most fields; biggest gains from McArthur River field





SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

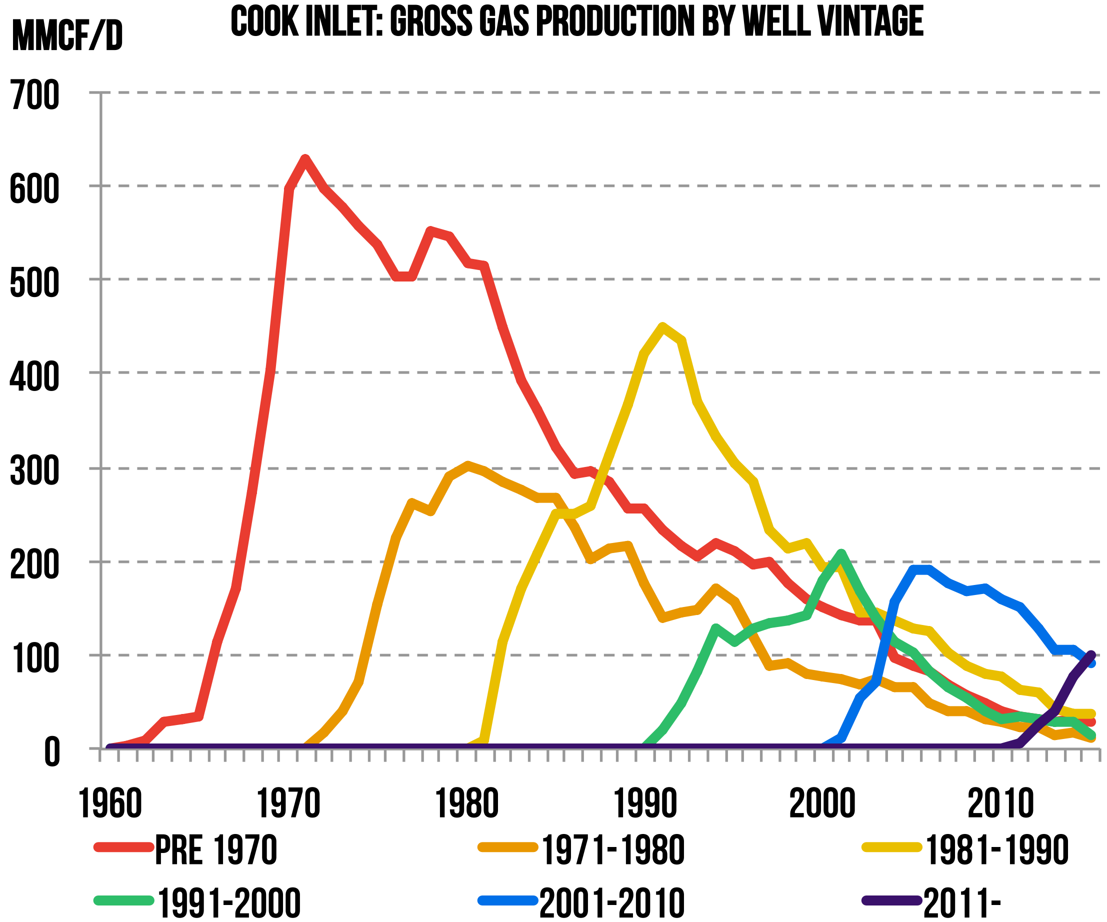
GAS FLATTENING FROM NEW WELLS IN EXISTING FIELDS

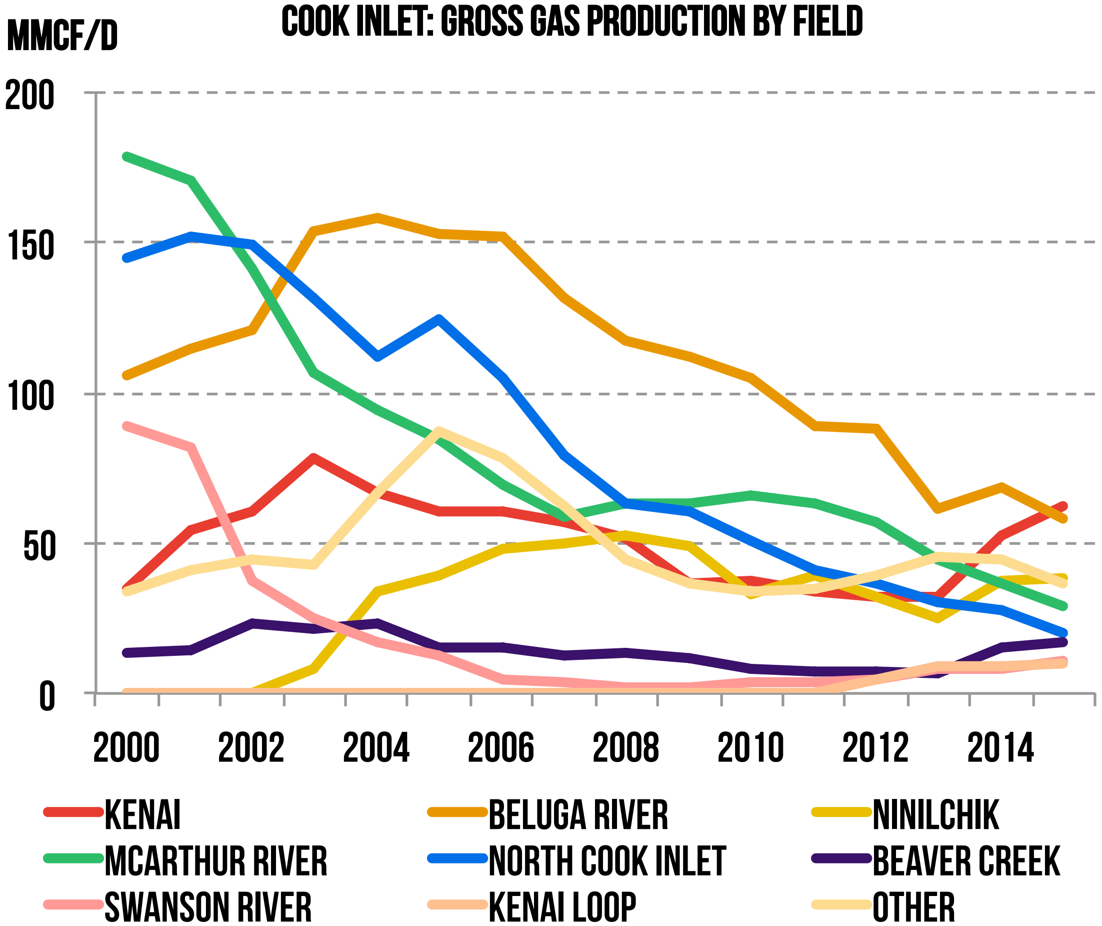
Wells drilled after 2011 have added about 100 mmcf/d of new production

Production from Beluga River, Ninilchik, and North Cook Inlet declined by 85.7 mmcf/d in 2011–2015

Growth from Kenai (+28 mmcf/d), Beaver Creek (+10), Kenai Loop (+9.7), and Swanson River (+7.3)

Only Kenai Loop is (major) new field (first gas in 2012); other growth from workovers and new wells





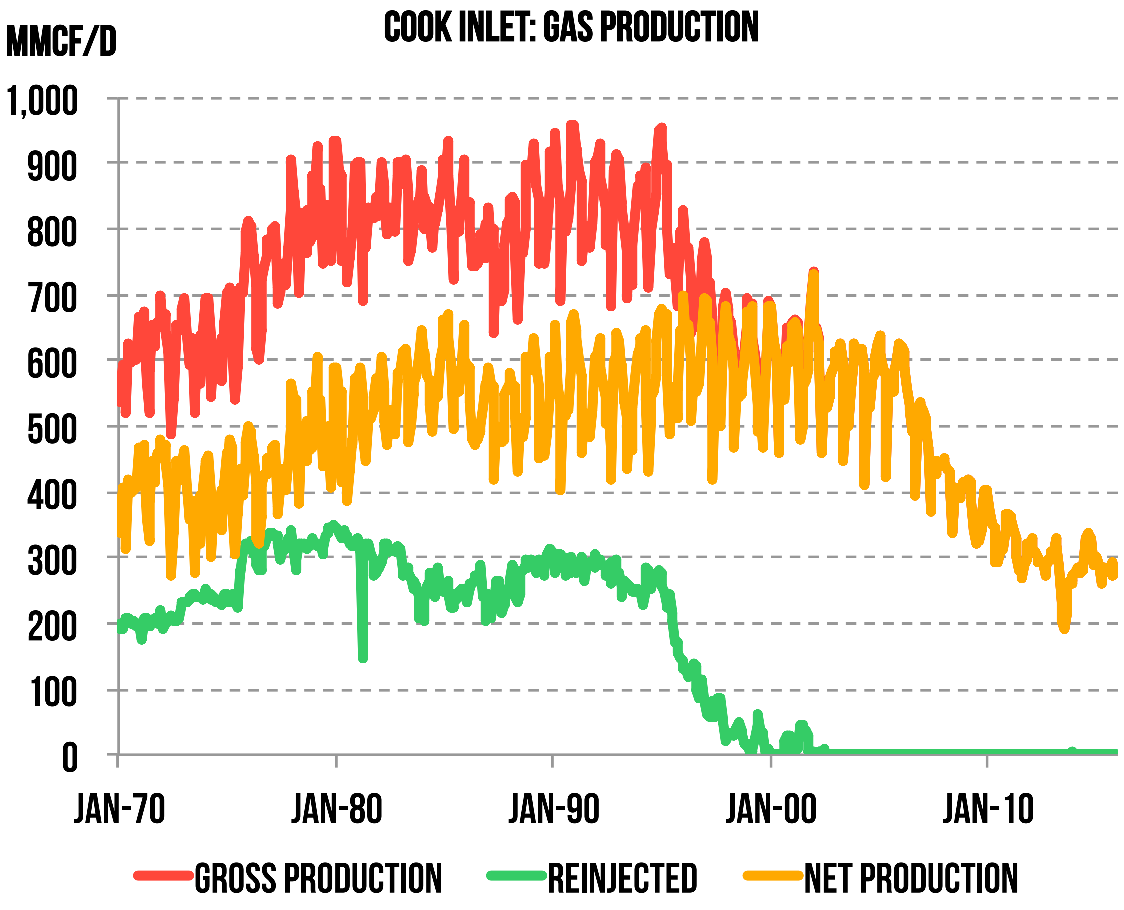
SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

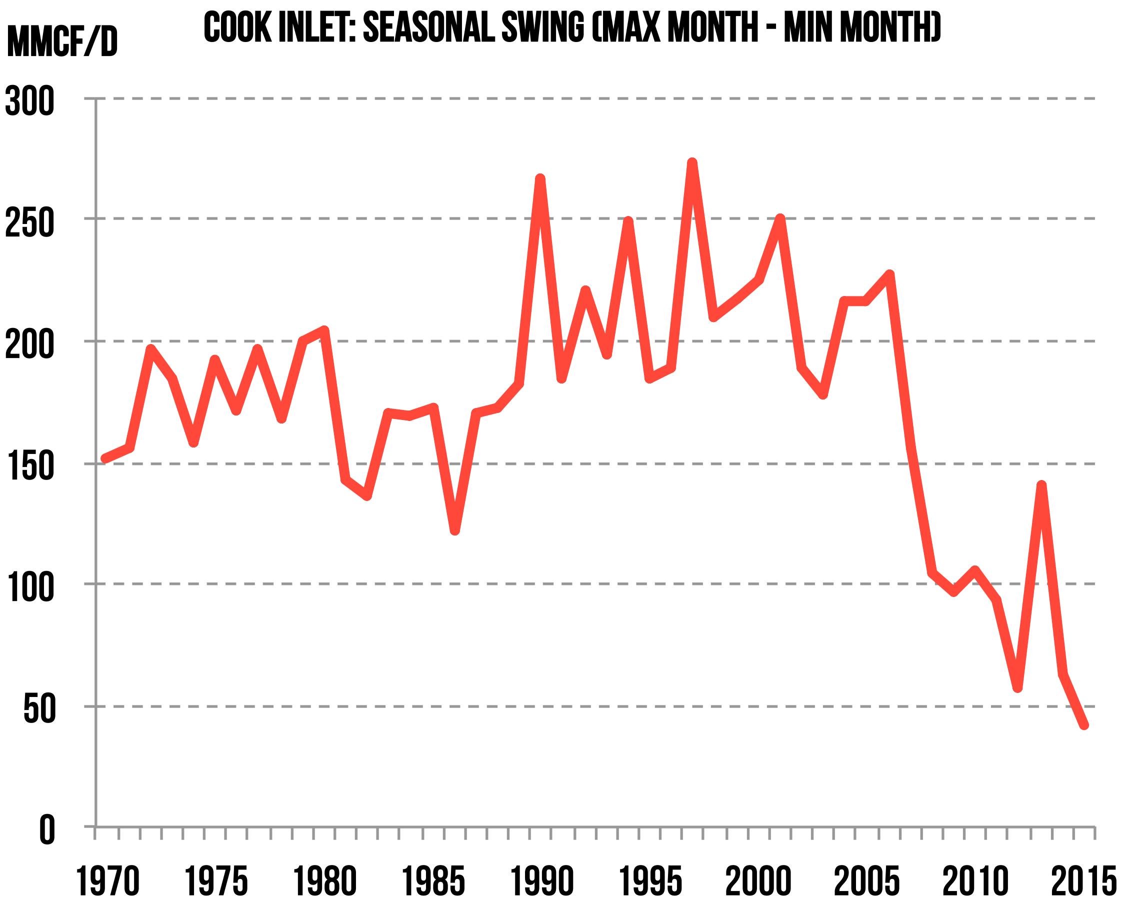
MATURE BASIN HAS LIMITED SEASONAL PRODUCTION FLEX

Historically, gas production in Cook Inlet has provided seasonal flex

As production has matured, that seasonality has gone away

Since 2006, we have seen the seasonal swing (max-min month) drop to below 100 mmcf/d





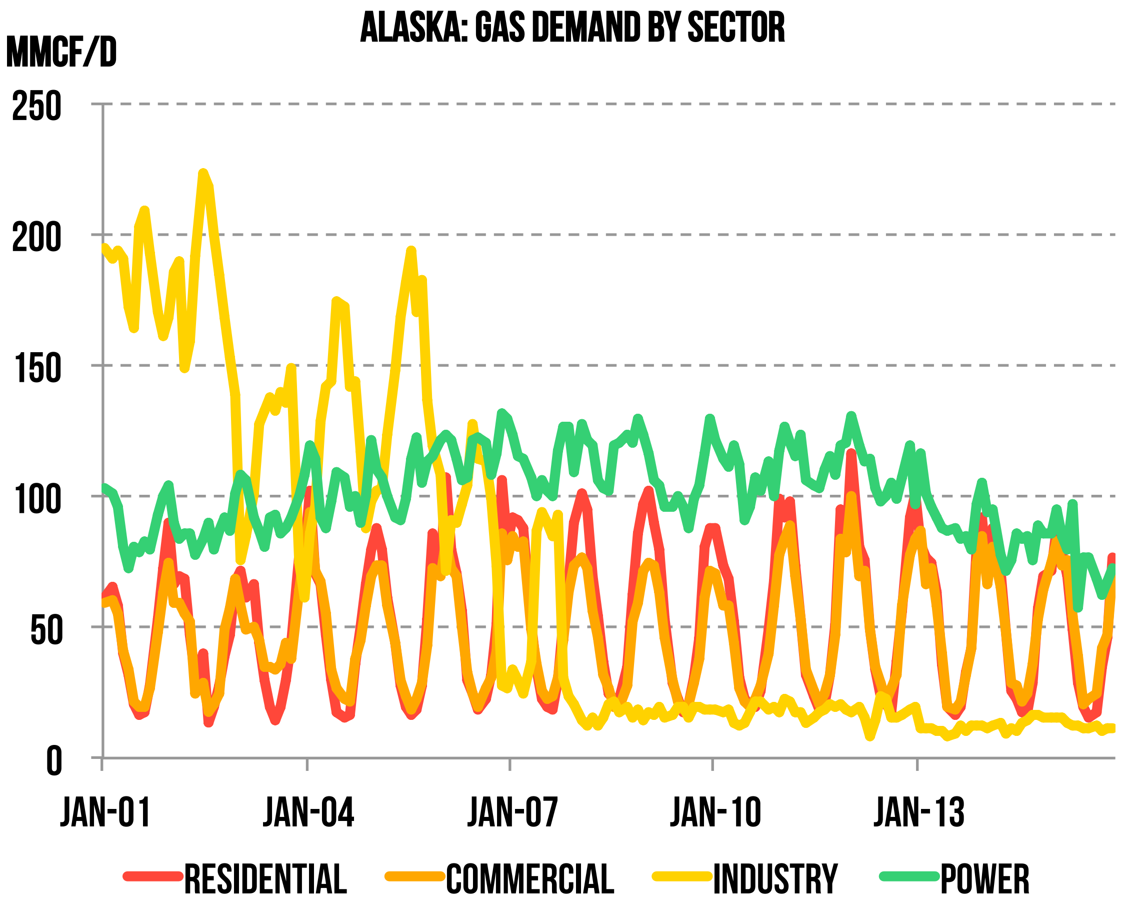
SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

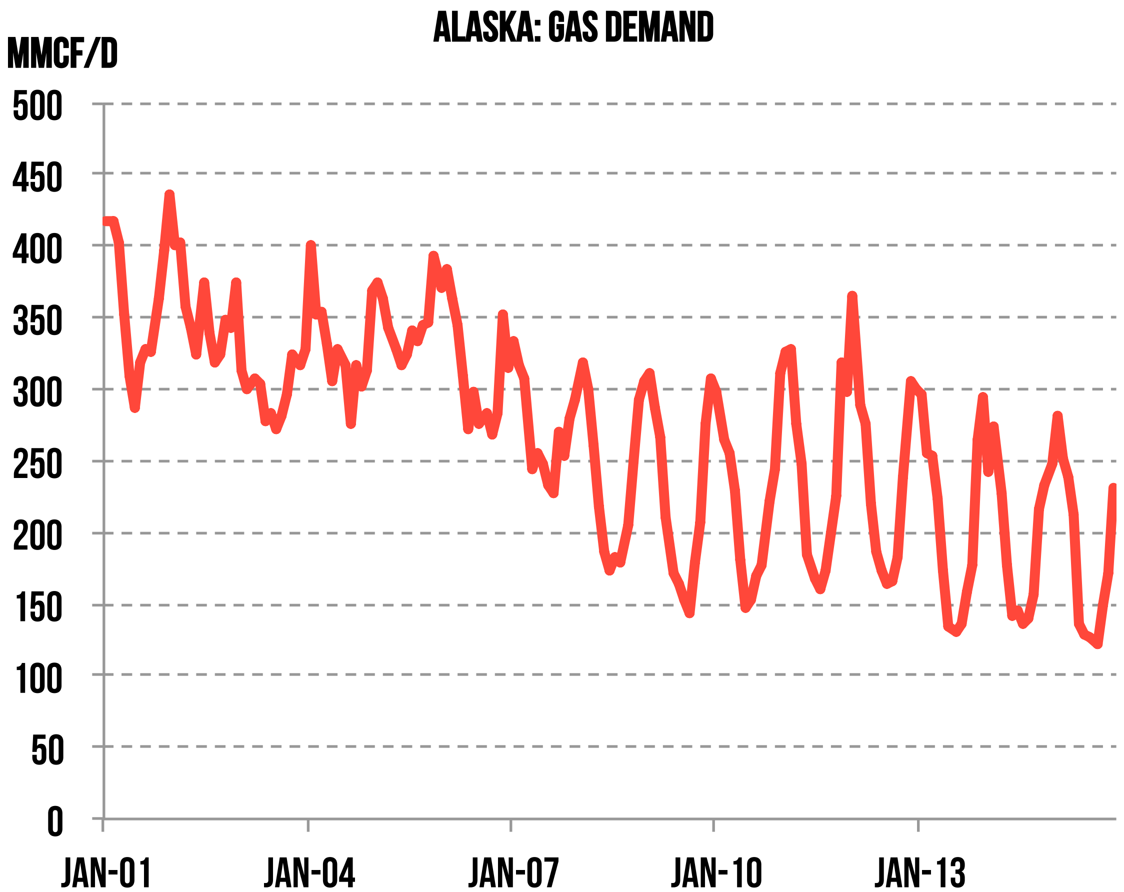
DEMAND HAS, MEANWHILE, BECOME MORE SEASONAL

Historically, gas production was either exported or consumed in industry (nitrogen)

Lower consumption in industry has made the demand profile more seasonal (lack of "base-load" demand)

In 2003–2005, industry consumption was flexible enough to serve a seasonal purpose





SOURCE: ENERGY INFORMATION ADMINISTRATION, ALASKA NATURAL GAS CONSUMPTION BY END USE

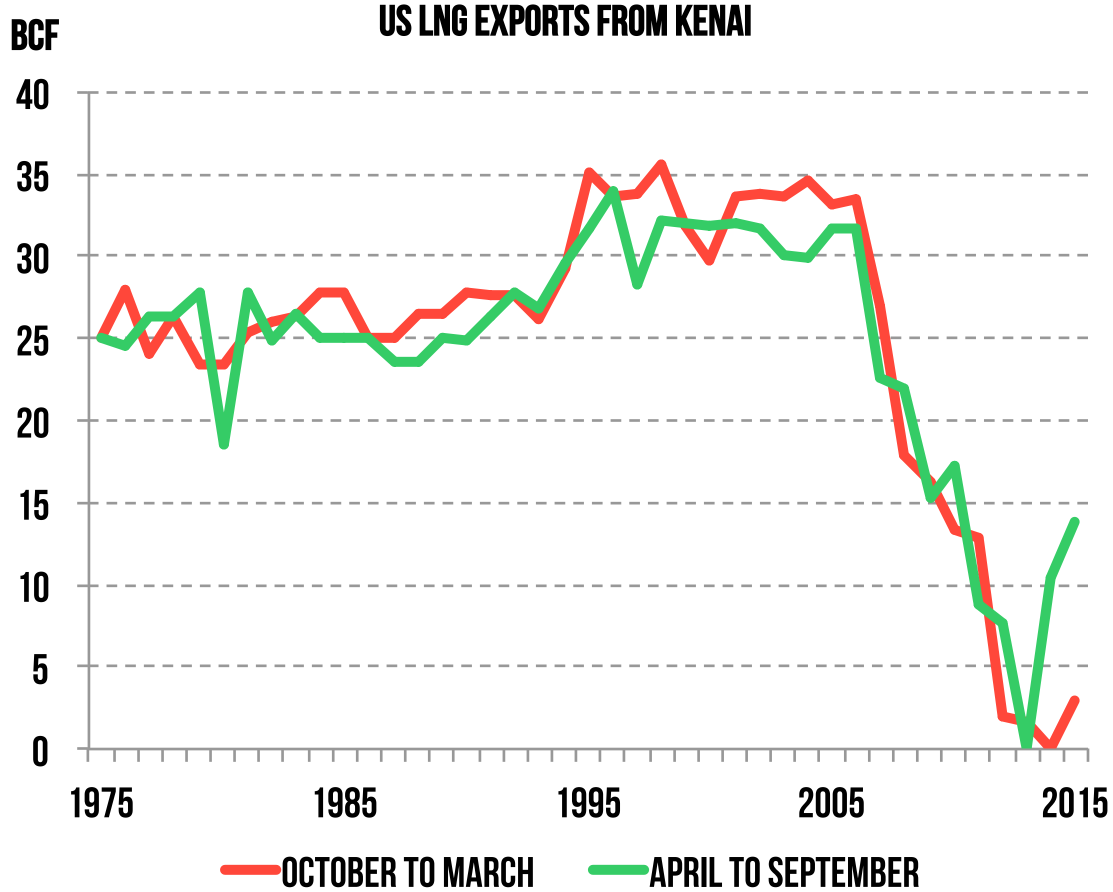
RECENTLY, EXPORTS HAVE OFFERED A SEASONAL OUTLET

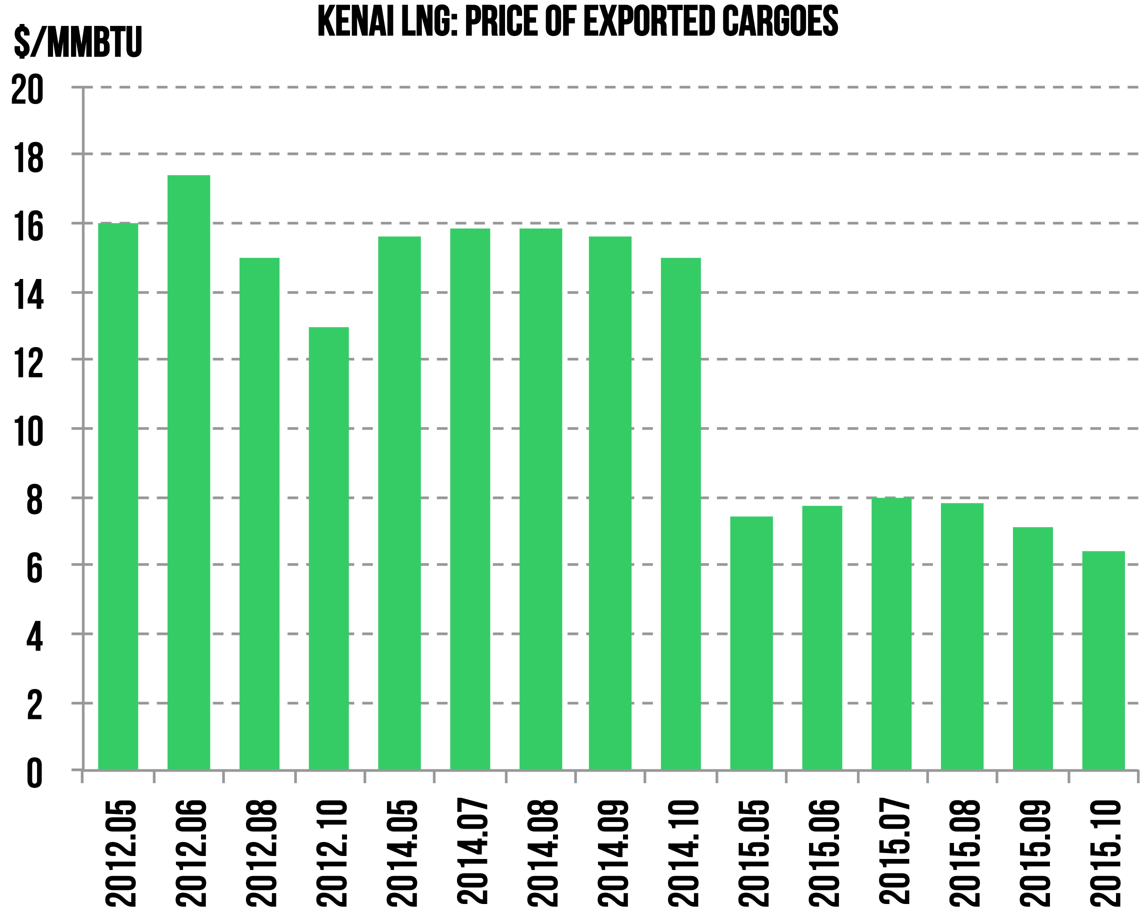
Historically, LNG exports were not particularly seasonal: exports in winter and summer were similar

Since 2012, LNG exports have taken place largely in the summer

In 2014 and 2015, Kenai exported 13 and 16 bcf respectively, helping to support seasonal flexibility

How will lower prices and ConocoPhillips' divestment of upstream in Cook Inlet impact this outlet?





SOURCE: ENERGY INFORMATION ADMINISTRATION

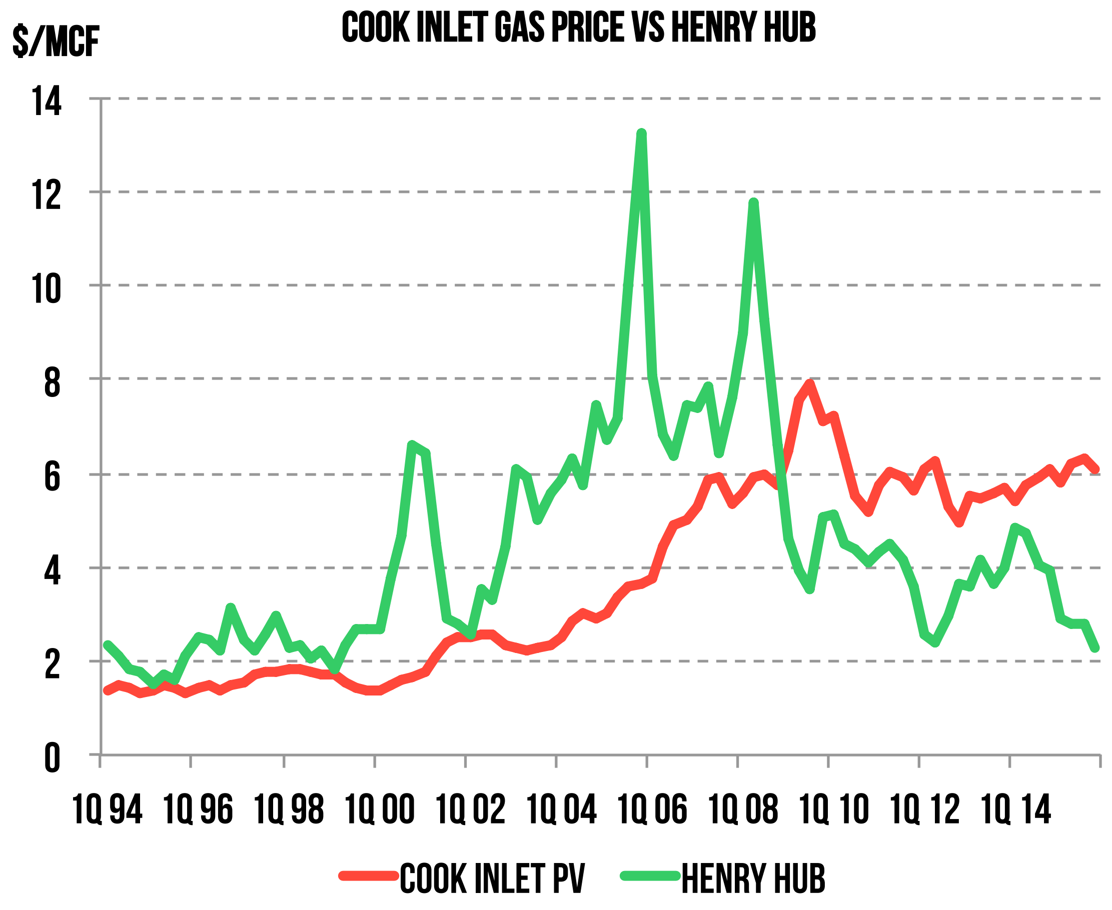
GAS PRICES HAVE RISEN CONSIDERABLY POST 2004

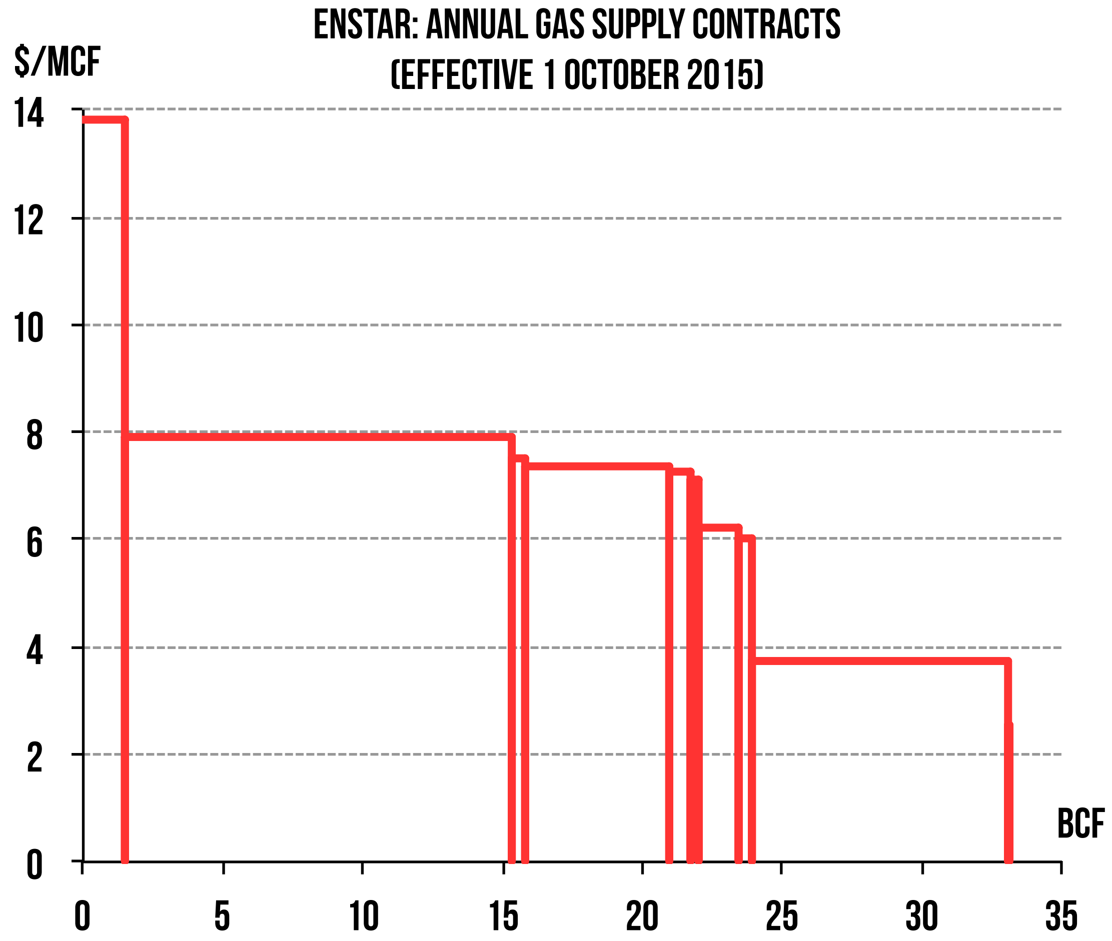
Historically, gas prices in Cook Inlet have been equal to or (more often) below Henry Hub

Since 2004, there has been a steady rise in gas prices; since 2010, prices were between \$5 and \$6/mcf

But there is considerable supply trading above this level, at \$8+ (and rising depending on contract)

Other jurisdictions have found \$5-\$7/mcf is sufficient to produce most expensive gas (shale, deepwater)





SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION (COOK INLET PV); ENERGY INFORMATION ADMINISTRATION (HENRY HUB); ENSTAR, DETERMINATION OF GAS COST ADJUSTMENT